TECHNOLOGICALLY DETAILED MODELING AND ANALYSIS OF INDUSTRIAL ENERGY USE AND CO_2 EMISSIONS IN TURKEY WITHIN THE FRAMEWORK OF A MARKAL BASED BOTTOM-UP NATIONAL ENERGY MODEL

by
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To my father...

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ABSTRACT

TECHNOLOGICALLY DETAILED MODELING AND ANALYSIS OF INDUSTRIAL ENERGY USE AND CO_2 EMISSIONS IN TURKEY WITHIN THE FRAMEWORK OF A MARKAL BASED BOTTOM-UP NATIONAL ENERGY MODEL

This study examines the long term supply demand planning and balancing of the national energy system and related CO_2 emissions with special emphasis on the industrial sector. The MARKAL modeling framework is deployed where all technological, emission related and cost parameters of available energy sources, conversion, transmission and consumption technology alternatives, as well as final energy demands are externally estimated for each time period and fed into the model as parameters.

Within this context, special attention is paid to industrial sector in that most energy consuming nine subsectors (namely manufacture of chemicals, cement, glass, iron & steel, non-ferrous metals, pulp & paper, motor vehicles, food & beverage and textiles) are individually represented with their cost, technology and emission related parameters compiled based on data painstakingly obtained from many expats and industrial enterprises. Using the model, a reference scenario is defined and optimized in cost. Then, other scenarios directly constraining the CO_2 emissions or applying tax per ton of emitted CO_2 are set and analyzed in terms of total costs and effectiveness in emission reduction. The scenarios also involve variation of levels with regard to nuclear capacity and carbon capture and storage (CCS) technology. Results obtained are discussed.

ÖZET

MARKAL'I TEMEL ALAN TEKNOLOJİK DETAYLI ULUSAL ENERJİ MODELİ ÇERÇEVESİNDE TÜRKİYE'DEKİ ENDÜSTRİYEL ENERJİ KULLANIMININ VE CO_2 SALIMININ MODELLENMESİ VE ANALİZİ

Bu çalışmada ulusal enerji sisteminin uzun dönemli arz talep planlaması ve dengelenmesi ve ilgili CO_2 salımı, endüstriyel sektör vurgusu ile incelenmiştir. MARKAL modeli çerçevesi kullanılmış ve mevcut enerji kaynaklarına ilişkin tüm teknolojik, mali ve salım ile ilgili değerler ve de nihai enerji talepleri dışşsal olarak tahmin edilmiş ve modele parametre olarak beslenmiştir.

Bu bağlamda, endüstriyel sektöre özel önem verilmiş ve en yoğun enerji tüketen dokuz alt sektör (kimyasal madde, çimento, cam, demir–çelik, demir harici metal, kağıt ve türevleri, otomotiv, gıda & içecek ve tekstil üretimi) birçok uzman ve endüstriyel kurumlardan özenle edinilen kendi maliyet, teknoloji ve salım ile ilgili parametreleri ile modelde ayrı ayrı temsil edilmişlerdir. Bu model kullanılarak, bir referans senaryo tanımlanmış ve maliyet bakımından optimize eniyilenmiştir. CO_2 salımını doğrudan kısıtlayan veya ton CO_2 emisyonu başına vergi uygulayan senaryolar tanımlanmış ve hem toplam maliyet hem de salım azaltımındaki etkinlik bakımından analiz edilmişlerdir. Aynı zamanda, senaryolarda nükleer kapasite ve karbon yakalama ve saklama (CCS) teknolojisi ile ilgili seviye değişiklikleri de uygulanmıştır. Elde edilen sonuçlar değerlendirilmiştir.

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LIST OF ABBREVIATIONS

BASIS	The Base Scenario, no nuclear, no CCS
BASIS_FF	Base scenario, fast nuclear, fast CCS
BASIS_FS	Base scenario, fast nuclear, slow CCS
BASIS_SF	Base scenario, slow nuclear, fast CCS
BASIS_SS	Base scenario, slow nuclear, slow CCS
CCS	Carbon capture and storage
DRY	Drying & seperation
EIE	Elektrik Etüt İşleri İdaresi
ELC	Electricity
EU	The European Union
FIXOM	Fixed operations and management costs [in million £/ (PJ x year)]
GEN10_FF	10 per cent reduction, fast nuclear, fast CCS
GEN10_FS	10 per cent reduction, fast nuclear, slow CCS
GEN10_SF	10 per cent reduction, slow nuclear, fast CCS
GEN10_SS	10 per cent reduction, slow nuclear, slow CCS
GEN20_FF	20 per cent reduction, fast nuclear, fast CCS
GEN20_FS	20 per cent reduction, fast nuclear, slow CCS
GEN20_SF	20 per cent reduction, slow nuclear, fast CCS
GEN20_SS	20 per cent reduction, slow nuclear, slow CCS
GEN30_FF	30 per cent reduction, fast nuclear, fast CCS
GEN30_FS	30 per cent reduction, fast nuclear, slow CCS
GEN30_SF	30 per cent reduction, slow nuclear, fast CCS
GEN30_SS	30 per cent reduction, slow nuclear, slow CCS
GEN40_FF	40 per cent reduction, fast nuclear, fast CCS
GEN40_FS	40 per cent reduction, fast nuclear, slow CCS
GEN40_SF	40 per cent reduction, slow nuclear, fast CCS
GEN40_SS	40 per cent reduction, slow nuclear, slow CCS
GEN50_FF	50 per cent reduction, fast nuclear, fast CCS

GEN50_FS	50 per cent reduction, fast nuclear, slow CCS
GEN50_SF	50 per cent reduction, slow nuclear, fast CCS
GEN50_SS	50 per cent reduction, slow nuclear, slow CCS
GHG	Greenhouse gas
HTH	High thermal heat
IAU	Energy demand of the automotive industry
ICH	Energy demand of the chemicals industry
ICM	Energy demand of the cement industry
IELC	Electricity for use by industry
INVCOST	Total cost of investment in new capacity [in million £/ (PJ x year)]
IFB	Energy demand of the food & beverage industry
IGL	Energy demand of the glass industry
IIS	Energy demand of the iron & steel industry
INF	Energy demand of the non-ferrous metals industry
INGA	Natural gas for use by industry
IOI	Energy demand by other industrial usage
IPP	Energy demand of the pulp & paper industry
ITX	Energy demand of the textile industry
LTH	Low thermal heat
MOT	Running of motors
NGAS	Natural gas
OECD	Organisation for Economic Co-operation and Development
OSD	Automotive Manufacturers Association
OTH	Other uses of energy
OUT(ENC)p	Efficiency ratio
SEK	Swedish krona
STM	Steam
TAX10_FF	10 TL tax/ton CO_2, fast nuclear, fast CCS
TAX10_FS	10 TL tax/ton CO_2, fast nuclear, slow CCS
TAX10_SF	10 TL tax/ton CO_2, slow nuclear, fast CCS

TAX10_SS	10 TL tax/ton CO_2, slow nuclear, slow CCS
TAX20_FF	20 TL tax/ton CO_2, fast nuclear, fast CCS
TAX20_FS	20 TL tax/ton CO_2, fast nuclear, slow CCS
TAX20_SF	20 TL tax/ton CO_2, slow nuclear, fast CCS
TAX20_SS	20 TL tax/ton CO_2, slow nuclear, slow CCS
TAX30_FF	30 TL tax/ton CO_2, fast nuclear, fast CCS
TAX30_FS	30 TL tax/ton CO_2, fast nuclear, slow CCS
TAX30_SF	30 TL tax/ton CO_2, slow nuclear, fast CCS
TAX30_SS	30 TL tax/ton CO_2, slow nuclear, slow CCS
TAX40_FF	40 TL tax/ton CO_2, fast nuclear, fast CCS
TAX40_FS	40 TL tax/ton CO_2, fast nuclear, slow CCS
TAX40_SF	40 TL tax/ton CO_2, slow nuclear, fast CCS
TAX40_SS	40 TL tax/ton CO_2, slow nuclear, slow CCS
TAX50_FF	50 TL tax/ton CO_2, fast nuclear, fast CCS
TAX50_FS	50 TL tax/ton CO_2, fast nuclear, slow CCS
TAX50_SF	50 TL tax/ton CO_2, slow nuclear, fast CCS
TAX50_SS	50 TL tax/ton CO_2, slow nuclear, slow CCS
TL	Turkish lira
TUIK	Turkish Statistical Institute
USD	U.S. dollars

1. INTRODUCTION

The amount of energy usage and the number of diversified methods for energy production have greatly expanded in recent times. In the age of globalization, the efficiency of energy usage has begun to come into view, with overall cost minimization being one of the main goals. The modern age has also brought a new perspective of concern into the field: minimization of the negative impacts on the environment. One of the menacing forms of such environmental impacts is the emission of greenhouse gases into the atmosphere. Greenhouse gases (carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride) absorb and emit radiation within the thermal infrared range. As emission levels and atmospheric concentration of greenhouse gases increase, global temperature rises, endangering the survival of life on the earth.

It has been generally agreed by authorities that CO_2 emissions need to be reduced worldwide by 30 to 60 per cent in 2050 compared to the 2000 levels in order to keep CO_2 concentration in the atmosphere below 450 parts per million by volume, so that the increase in average global temperature would stabilize between 2.4 °C and 2.8 °C, compared to pre-industrialised levels [1]. This viewpoint is one of the main drives behind the Kyoto Protocol, a protocol to the United Nations Framework Convention on Climate Change (UNFCCC), signed and ratified by 187 states since its introduction in Kyoto on December 1997.

Turkey ratified the Kyoto Protocol on February, 2009. Although there is no specified rate of greenhouse gas reduction for developing countries in the Kyoto Protocol, Turkey —as an official EU candidate state— would like to strive for or at least move toward the mitigation targets set for the European Union. The protocol states that the European Union should reduce its greenhouse gas emissions by eight per cent in 2012 compared to the 1990 levels [2]. The EU is also willing to commit to 30 per cent reduction in 2020, if other developed countries also commit themselves to comparable emission reductions, and makes a interim commitment to achieve at least a 20 per cent reduction compared to the 1990 levels [3]. Although Turkey is not one of the prime polluters in terms of greenhouse gas emissions, it has been observed that it is not as efficient as the EU countries listed among the G7 states regarding internationally accepted objective measures such as emission to gross national product (GNP) ratio [4].

In 2004, energy use by the industrial sector resulted in emissions of 9.9 gigatons of carbon dioxide, 37 per cent of global CO_2 emissions from energy use [5]. Additionally, today much of the world's energy-intensive industry is located in the developing nations. Accordingly, the developing nations' share of industrial CO_2 emissions from energy use is 53 per cent [5]. The share of the industrial sector in carbon emissions is determined as 45 per cent in Turkey [6], fitting the profile of a developing country.

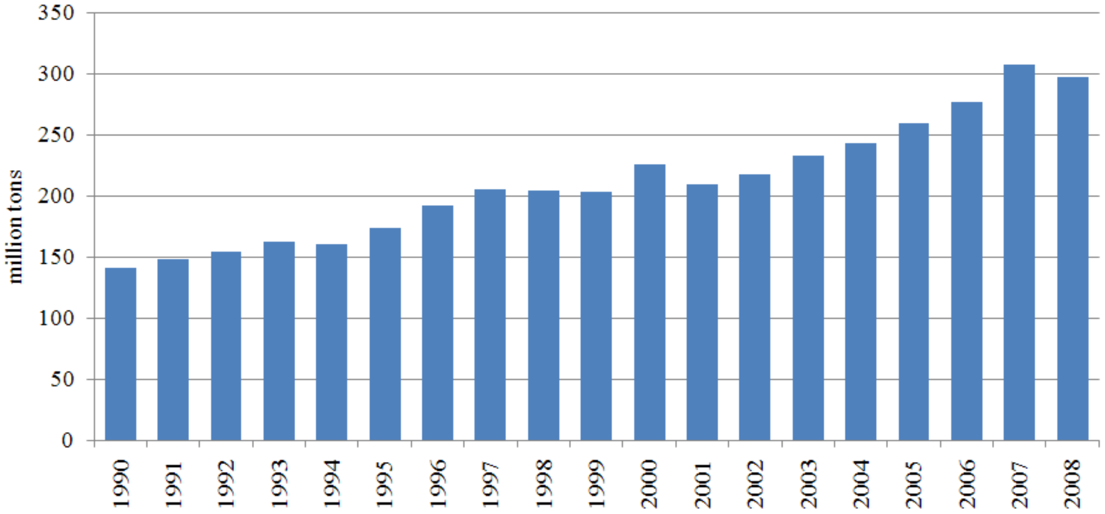

Figure 1.1. Aggregate CO_2 emissions in Turkey [7]

The breakdown of Turkish CO_2 emissions in the past show a prominent climbing trend in the share of the industry, reaching 45 per cent in 2006 from 24 per cent in 1970. While the share of agriculture is stagnant at about 5 percent, the share of the services sector rapidly declines in synchronization with the increase of the industrial sector [6]. Further details regarding CO_2 emissions can be found in Figure 1, while energy consumption shares of sectors are shown in Figure 1.

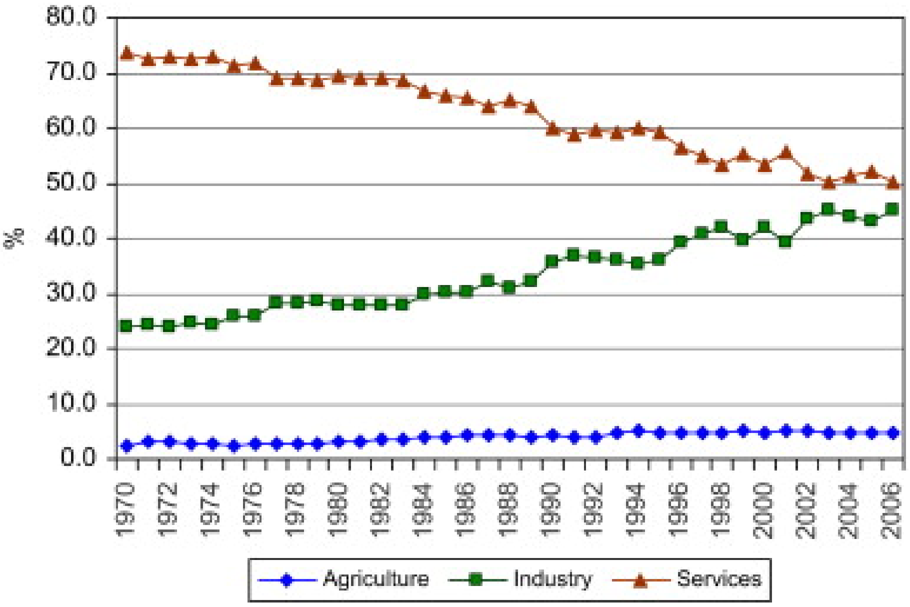

Figure 1.2. Shares of sectors in total CO_2 emissions in Turkey [6]

As a side note, CO_2 emissions per capita are relatively low in Turkey compared to many industrial countries [6]. In Turkey, economic circumstances and constraints can overcome environmental concerns easily, and it is important to develop and set persistent climate and energy policies before the growing economy and resource use puts increasing pressure on greenhouse emission mitigation and environmental concerns, in general [6]. Moreover, the CO_2 elasticities of income are relatively high due to limited substitution possibilities in production [9]. In conformity with of implementation of such energy policies, structural renovation promoting a more flexible economic structure will allow a smooth transition of the country into an emission reducing and sustainable growth path [9].

Due to the great share of the industrial sector in energy consumption and carbon emissions, to achieve a realistic assessment of current and future carbon emissions, detailed modeling of the industrial sector and analysis of various key industrial processes regarding their energy uses and demands prove essential.

This study relies on the existent framework of the MARKAL-Turkey model and expands the number of industry types and extends technological details pertaining to the industry sector. Then, a general assessment and projection of the carbon emissions

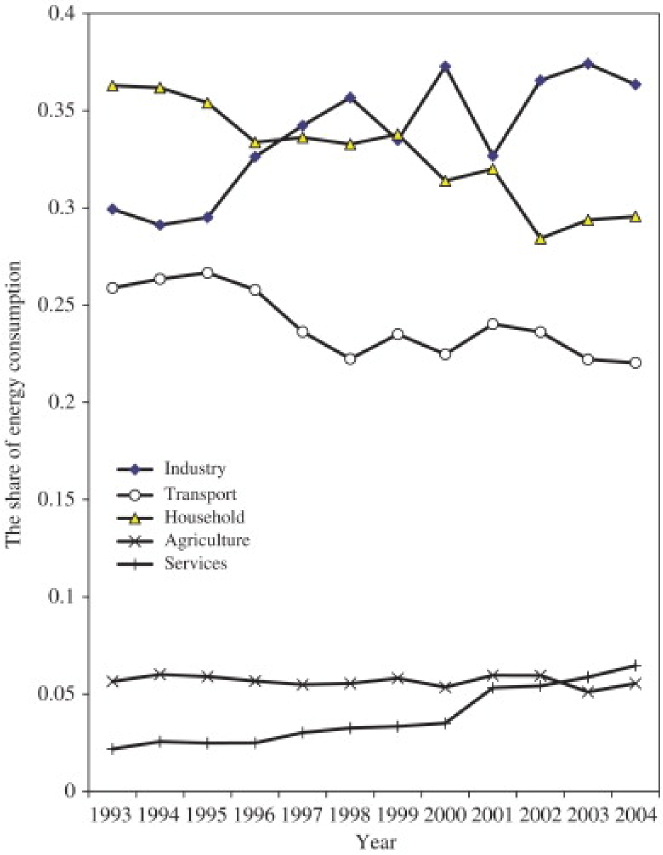

Figure 1.3. Shares of sectors in energy consumption in Turkey [8]

are conveyed while the status quo is maintained. Next, policy measures triggering —direct or indirect— mitigation of CO_2 emissions are scrutinized.

The work is presented in five chapters other than this one.

In Chapter 2, first a review of the recent noteworthy research in the subject of modeling and analysis of industrial energy use and reduction of CO_2 emissions is provided. Then, the various approaches to environment–energy–economy modeling are explored.

In Chapter 3, the employed model is introduced. In the first section, general information about the model is supplied and the second section identifies the MARKAL-Turkey model closely.

Chapter 4 describes the refinements and expansions accomplished on the industrial sector represented in the model and details the technologies pertaining to the introduced industries. In this context, the energy demands of nine industrial subsectors (namely manufacture of chemicals, cement, glass, iron & steel, non-ferrous metals, pulp & paper, motor vehicles, food & beverage and textiles) of industrial branches are investigated.

In Chapter 5, scenarios involving the application of policies promoting reduction of carbon emissions —either directly or indirectly— are defined and analyzed in effectiveness of emission reductions and total costs.

The final chapter, Chapter 6, includes conclusions and closing remarks and offers ideas for expansion and further improvement of this work.

2. LITERATURE SURVEY

2.1. Research in Modeling and Analysis of Industrial Energy Use and Mitigation of Industrial CO_2 Emissions

CO_2 emissions caused by industrial energy utilization constitute a significant share of the total CO_2 emissions in developing countries, as large as 51 per cent in Taiwan [10] and 62 per cent in South Korea [11]. Multi-period modeling of industrial energy use in whole or for a specific energy-intensive industry branch with national or regional focus has been an intriguing research topic, especially after the adoption of the Kyoto Protocol. Most of the research concentrates on areas of heavy industrial activity and on energy-intensive industry branches, such as iron & steel production industry.

Ordorica-Garcia et al. [12] use a mixed integer linear programming model to optimize the energy production by the oil sands industry in Canada and to examine the carbon dioxide emission in Alberta, while utilizing integrated CCS technology. The planning horizon of this work is set as 2030 and the maximum reduction in CO_2 emission attained in this research has been 39 per cent, causing about 20 per cent rise in total costs. It is observed that above 35 per cent of CO_2 reduction level, steam methane reforming (SMR) with carbon capture becomes the dominant technology.

Henriques Jr. et al. [13] discuss the potential of reducing CO_2 emissions caused by the Brazilian industrial sector under various low-carbon scenarios. The scenario set in this work encompasses the 2010–2030 period and foresees reduction rates reaching 43 per cent in industrial CO_2 emissions, in comparison to the baseline scenario reflecting current situations without major policy changes. The preferred scenario involves major technological investments in cement, iron & steel and ceramics industries and up to 850 million tons of CO_2 reduction, the results depict negative abatement costs, ensuring carbon emission mitigation and financial gains at the same time.

Ribbenhed et al. [14] investigate alternatives to reduce the volume and related costs of CO_2 emissions in the Swedish iron & steel industry. The study presents two options with CO_2 emission reduction rates of 6.5 per cent and 13 per cent, respectively. While the first option yields negative abatement cost estimates (indicating cost savings and emission reduction simultaneously), the 13 per cent reduction option shows abatement costs of between 130 and 186 SEK (equivalent of between 26 and 37 TL, in June 2010) per ton CO_2 reduced, depending on the applied interest rate.

Sirikitputtisak et al. [15] construct a multi-period mixed-integer non-linear energy planning model for Ontario. Construction time, fuel price change and CO_2 emission reduction constraints are used in the model. The work compares various scenarios with varying CO_2 emission reduction targets with respect to the base scenario where no CO_2 emission reduction is set. Carbon capture and storage, and fuel switching are employed to allow emission reduction, while keeping the associated costs relatively low. The cost analysis accomplished puts emphasis on cost changes of electricity among scenarios and concludes that the overall cost of electricity increases linearly as carbon dioxide emission reduction target increases.

Gielen et al. [16] suggest a number of CO_2 emission reduction options for the Japanese petrochemical industry, where energy efficiency is already among the highest in the world. The proposed strategy puts emphasis on new production processes and waste handling. Use of bioplastics and biomass feedstocks are offered as long term strategy, as they prove to be costly on the short term. Application of full measures leads to about eight percent reduction in Japanese greenhouse gas emissions, where five per cent share is due to changes on the supply and about three per cent change arises from changes in waste management. While the first half of greenhouse gas reduction proves cost effective, the other half has an associated abatement cost of 80 USD per ton of CO_2 reduced.

Wang et al. [17] examine the CO_2 emission reduction potential in China's iron and steel industry using a scenario-based modeling platform called LEAP (Long-range Energy Alternative Planning System). The model encapsulates the time range of 2000–

2030 and works on three different CO_2 emission abatement scenarios. Two scenarios yield reduced emission amounts of 51 and 107 million tons, while costing 9.3 billion and 81 billion US dollars, respectively. The study concludes that emission reduction largely depends on the adjustment of production processes (from a long term perspective).

Zhou et al. [18] analyze the potential for carbon mitigation in the Chinese ammonia industry, one of the most important fundamental industries in China. In addition to the base scenario denoting status quo without any emission constraints, there is a scenario which considers the results of fuel switching and one more scenario analyzing both fuel switching and technological investment, simultaneously. While fuel switching alone offers 33.5 million tons of CO_2 emission reduction, with the implementation of technological investment, the reduction potential reaches 74 million tons of CO_2 in a decade. Alongside to the technological improvements in the industry, carbon capture and storage technology on the energy supply side is also considered as means of carbon mitigation.

Gielen and Moriguchi [19] utilize a specific model developed for the iron & steel industry called STEAP (Steel Environmental Assessment Program) to define various tax policies concerning CO_2 emission of the Japanese iron & steel industry and analyzes their effects on CO_2 emission reductions. Also, global and local tax strategies are compared, and in case of major differences in tariffs, carbon leakage occurs. The results indicate that a CO_2 tax of 20 US dollars per ton in combination with an import price of 20 to 40 US dollars per ton of steel prevents carbon leakage and results in 41 per cent reduction regarding the CO_2 emission caused by the Japanese iron & steel industry.

The conclusion reached in the aforementioned research is in general, that up to a certain degree —depending on the matureness of the sector and region— implementation of a CO_2 emission constraint proves cost-effective and beyond this degree, mitigation costs of greenhouse gas emissions incur a severe increase. Another general observation is that with short term returns in mind, first measures requiring relatively lower investment costs and yielding more CO_2 reduction per dollar —such as fuel switching— are applied. However, to achieve sustainable and permanent results in the long term, further measures (such as the use of biomass feedstocks, bioplastics and carbon capture and storage) are necessary, which turn out to be more expensive, in general.

2.2. Approaches in Environment-Energy-Economy Modeling and Policy Making

Various approaches, models and methodologies are employed in the modeling of energy and environmental systems and application of policies. Generally, the associated research can be classified in two groups according to the choice of focal point. The first group of works concentrate on the economy and represent energy systems as a subsector of the economy. This group of works approach energy systems as a whole and examine the fuel input, energy and emission output and associated costs from a macroeconomic standpoint. Also, the econometrics regarding these parameters are employed to assess the supply and demand issues of the energy sector entirely. These models are be labeled as "top-down approach" models, since they are not interested in details per se, such as supply of primary energy, conversion technology efficiencies, cost associated with conversion and usage and technology investment costs.

Models utilizing the top-down approach can be further examined in two classes, aggregate and disaggregate economic equilibrium models. The aggregate economic equilibrium model is by and large interested in the application of energy policies and their effects on the economy and carbon emissions. Investment schemes and energy demands are the important main variables within this model. The demand amount determines the position on the economies of scale and the model fits the resource amount according to the extraneously-set price. New technology investments and allocations are of primary concern and are important tools for mitigating carbon dioxide emissions. In this type of models, the economy is represented as a whole. Application models based on such macro-economic modeling framework rely heavily on past economic data. CETA [20], GLOBAL 2100 [21], GRAPE [22], MARKAL-MACRO [23], MEEET [24], MERGE [25], MIS [26] and RICE [27] are among models utilizing the aggregate economic equilibrium model.

Disaggregate economic equilibrium models, representing the top-down approach, comprise a diversified structure of sectors. These sectors have their own demands, prices, rates and wages. Since there are interrelations and trade within these sectors, such models tend to exhibit an ample amount of interactivity, through which economic equilibrium is aimed. While aggregate economic equilibrium models show a macro-economic approach, disaggregate models are on the micro-economic side. ABARE [28], DREAM [29], ENVEEM [30], JW [31], G-Cubed [32], GOULDER [33], GREEN [34], IGEM [35], MULTI [36] and PESTES [37] are representatives of disaggregate economic equilibrium models.

The second group of studies, in contrast, focuses on the energy demand of several sectors (such as services, industrial, agricultural etc.) and is interested in how this demand is to be met. Conversion efficiencies, availability of primary energies and costs regarding demand processes are key data and must be assessed attentively. The financial cost associated with the fulfillment of the total energy demand is the main concern. If no other constraints are defined, the choice of fuels, substitution of conversion technologies and employed end-use processes are made to serve solely the minimal cost. If the model is interested in a span of multiple time periods, the investment decisions (for primary energy source extraction technologies, conversion technologies and process technologies) have to be considered. This approach is defined as “bottom-up” and the related research tends to externalize other aspects of economy, such as market interactions and business profitability.

Energy sector equilibrium models are in this second group of studies, the bottom-up type employing partial equilibrium approach. Investment costs, operation and maintenance costs, emission amounts and taxes (if applicable) are compiled from each process included in the model. End-demands differ by sector or industry and the model tries to fulfill these demands, while maintaining minimum costs within the feasible set. Such models encompass elaborate technology details both for the end-use and for the energy production and conversion technologies. ETP [38], MARKAL [39], MESSAGE

[40] and SAGE [41] are bottom-up models which aim to maintain the energy sector equilibrium while keeping total system costs at a minimum.

This study centers on the bottom-up and long term supply–demand planning and balancing of the national energy sector (i.e. sectoral equilibrium), based on the MARKAL approach. The development of the model is presented in the next chapter.

3. THE MARKAL MODEL

3.1. Definition and Uses of the MARKAL Model

MARKAL (acronym for MARKet ALlocation) is a widely applied bottom-up, dynamic and mostly a linear programming (LP) based modeling approach developed by the Energy Technology Systems Analysis Programme (ETSAP) of the International Energy Agency (IEA) [42]. MARKAL depicts, in considerable detail, both the energy supply and demand side of the energy system. MARKAL provides policy makers and planners in the public and private sector with extensive and detailed decision suport regarding available (defined and inputted) information and energy producing and consuming technologies, and it can provide an understanding of the interplay between the macro-economy and energy use [43]. As a result, this modeling framework has contributed to national and local energy planning, and to the development of carbon mitigation strategies.

MARKAL is one of the the most ubiquitous methods for bottom-up energy and environment systems modeling, especially when customizable detailing of processes is of importance. There is innumerable research deploying the MARKAL family of models for national or regional energy planning and carbon mitigation strategies. Some interesting applications are worthy of credit, such as Ko et al. for the power sector in Taiwan [44], Jiang et al. for natural gas consumption in Beijing, Guangdong and Shanghai [45], Gül et al. for the analysis of global personal transport [46], Kannan and Strachan for the residential energy sector in the United Kingdom [47], Mallah and Bansal for the renewable energy use in electricity generation in India [48], van den Broek et al. for the electricity sector with CCS in the Netherlands [49], Jegarl et al. for general CO_2 emission mitigation in Korea [50], Schulz et al. for the energy consumption per capita in Switzerland [51], Wright et al. for the Cuban power sector [52] and Rosenberg et al. for the future market penetration of hydrogen vehicles in Norway [53].

The MARKAL family of models can answer a number of different policy and planning questions. The widest current applications are for the analysis of policies designed to reduce carbon emissions from energy and materials consumption. Since the framework depicts individual technologies, it is particularly useful for the evaluation of policies that promote the use of technologies. These technologies promote greater efficiency in energy or materials, or development and use of new technologies. Most aggregate modeling frameworks —e.g., macroeconomic models— lack this capacity. Whereas impacts of specific programs may not be identified in the output of those other models, the impacts can be identified in the output from MARKAL. Considering that policies affecting technology choice represent one of the primary means for reducing greenhouse gases, this is an important feature [39].

As with the most energy system models, energy carriers in MARKAL link the conversion and consumption of energy. This user-tailored network includes all energy carriers involved with primary supplies (e.g., mining, petroleum extraction, etc.), conversion and processing (e.g., power plants, refineries, etc.), and end-use demand for energy services (e.g., boilers, automobiles, residential space conditioning, etc.) [39]. The demand for energy services may be set apart by sector (i.e., residential, manufacturing, transportation, and commercial), by specific functions within a sector (e.g., residential air conditioning, heating, lighting, hot water, etc.) and by region, if desired. The building blocks given in Figure 3.1 represent this network, referred to as a Reference Energy System (RES).

A number of limitations exist for this version of the MARKAL family. One of those limitations is the assumption of "perfect information" and foresight, which precludes incorporation of uncertainty in the analysis. The dynamic nature of MARKAL implies that past decisions and future constraints are included in the decision process. Thus, if there is the expectation that limits will be imposed on greenhouse gas emissions, this information will be used in the decision process to expand or decrease the use of certain energy technologies, or to choose less carbon-intensive capital stocks during the planning horizon. As a result, structural changes in the capital stock may be explored, but those changes are limited to what is both economically and technically

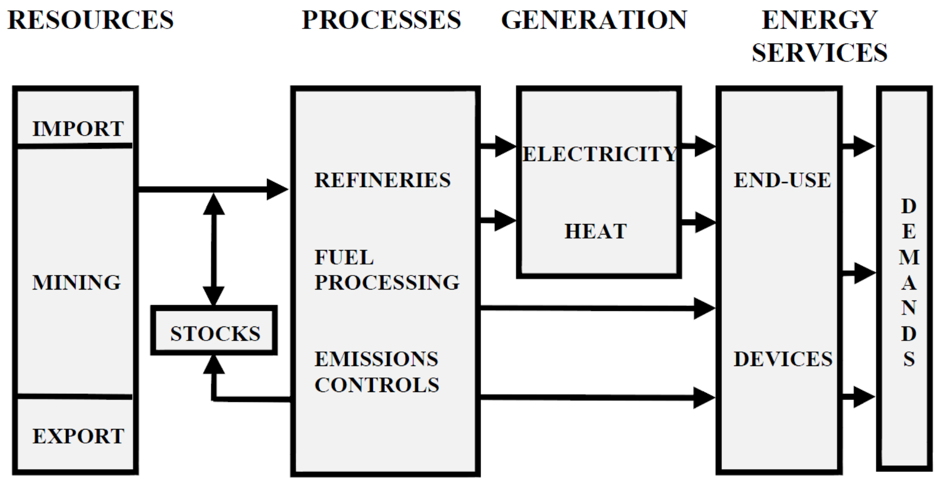

Figure 3.1. MARKAL Building Blocks [43]

viable [39]. Nevertheless, the uncertainties encircling critical issues such as mitigation of CO_2 emissions may be evaluated through the development of multiple scenarios which is the approach pursued in this work.

3.2. Mathematical Formulation of the MARKAL

In this section, a streamlined formulation of the equations of the MARKAL linear model is presented. Exceptions and some complexities that are not essential to a basic understanding of the principles of the model are left out. The information given here heavily relies on the documentation of MARKAL by Loulou et al. [54].

3.2.1. Indexes

- t: time period
- k: technology
- s: time-slice
- c: commodity (energy or material)
- l: price level (used only for multiple sources of the same commodity distinguished only by their unit cost)

3.2.2. Decision Variables

- INV(t,k): new capacity addition for technology k, in period t. Note that an investment made in period t is assumed to occur at the beginning of that period, and remains available until the end of its lifetime.
- CAP(t,k): installed capacity of technology k, in period t.
- ACT(t,k,s): activity level of technology k, in period t, during time-slice s. ACT variables are not defined for end-use technologies, for which it is assumed that activity is always equal to available capacity. With the exception of the conversion technologies, only annual activity is tracked (and the s index dropped).
- Mining(t,c,l): quantity of commodity c extracted at price level l in period t; the coefficient in the objective function is the unit cost of extracting the commodity, as provided by the user. These are domestic production resources, including physical renewables (such as biomass and municipal solid waste).
- Import(t,c,l), Export(t,c,l): quantity of commodity c, price level l, exogenously imported or exported in period t. It is important to note that the model does not automatically balance the quantities exported and imported.
- D(t,d): demand for end-use d, in period t.x
- ENV(t,p): emission of pollutant p in period t.

3.2.3. Objective Function

$$NPV = \sum_{t=1}^{t=NPER} (1+d)^{NYRS\cdot(1-t)} \cdot ANNCOST(t) \cdot (1 + (1+d)^{-1} + (1+d)^{-2} \\ + \cdots + (1+d)^{1-NYRS})$$

where:

NPV is the net present value of the total cost (the MARKAL objective function),

d is the general discount rate,

NPER is the number of periods in the planning horizon,

NYRS is the number of years in each period t,
and ANNCOST(t) is the annual cost in for period t.

$$
\begin{aligned}
ANNCOST(t) = \sum_{k} \{ & AnnualizedInvcost(t,k) \cdot INV(t,k) \\
& + Fixom(t,k) \cdot CAP(t,k) \\
& + Varom(t,k) \cdot \sum_{s,s} ACT(t,k,s) \\
& + \sum_{c} [Delivcost(t,k,c) \cdot Input(t,k,c) \cdot \sum_{s} ACT(t,k,s)] \} \\
& + \sum_{c,s} \{ Miningcost(t,c,l) \cdot Mining(t,c,t) \\
& + Importprice(t,c,l) \cdot Import(t,c,l) \\
& - Exportprice(t,c,l) \cdot Export(t,c,l) \} \\
& + \sum_{c} \{ Tax(t,p) \cdot ENV(t,p) \} \\
& + \sum_{d} \{ DemandLoss(t,d) \}
\end{aligned}
$$

The total annual cost ANNCOST(r,t) is the sum over all technologies k, all demand segments d, all pollutants p, and all input fuels f, of the various costs incurred, namely: annualized investments, annual operating costs (including fixed and variable technology costs, fuel delivery costs, costs of extracting and importing energy carriers), minus revenue from exported energy carriers, plus taxes on emissions, plus cost of demand losses.

3.2.4. Constraints

3.2.4.1. EQDEM(t,d) - Satisfaction of Demands. For each time period t, demand d, the total activity of end-use technologies servicing that demand must be at least equal to the specified demand.

$$
\begin{aligned}
Sum\{\text{over all end-use technologies k, such that k supplies service d}\} \text{ of } CAP(t,k) \\
= D(t,d)
\end{aligned}
$$

For example, the demand of the textiles industry may be satisfied by a combination of several types of energy (high heat, low heat, drying, etc.).

3.2.4.2. EQUTL(t,k,s) - Use of capacity. For each technology k, period t, and time-slice s, the activity of the technology may not exceed its available capacity, as specified by a user defined availability factor.

$$ACT(t,k,s) \leq AF(t,k,s) \cdot CAPUNIT \cdot CAP(t,k)$$

Note that this constraint is not written for end-use technologies, because an activity variable is not defined for them. Activity for end-use technologies is always assumed to be directly proportional to their installed capacities. For non-conversion technologies only annual availability is tracked, so the s index is dropped.

3.2.4.3. Other Constraints. Capacity transfer, energy balance, electricity and heat peak reserve constraint, emission constraint or tax, electricity baseload constraint and user-defined constraints are other types of constraints present in the MARKAL model. Details regarding these constraints are not given here, but detailed information can be found in the MARKAL documentation [54].

3.3. The MARKAL-Turkey Model

The aim of this study is to analyze the CO_2 emissions caused and the costs realized by the overall and sectoral national energy use, with an emphasis on industrial energy needs. The general framework of the mentioned MARKAL model together with the data associated with non-industrial sectors and final demands are based on a previous MARKAL study of the national energy sector. In the context of this study, a set of new scenarios are developed and the industrial part of the model is enhanced, by investigating various industrial sub-sectors and their energy needs and ways of consumption.

In this model, which is aimed to analyze emission caused by the energy use and to anticipate the long term changes in volume and costs associated with emission reductions, the reference year is taken as 2006 and the time horizon is set as 2051 (depicted in five year intervals). Energy equilibrium, supply and demand amounts of the reference year are integrated into the model. In the designation of investment and operational costs for various technologies and in forecasting similar parameters regarding technologies planned to be acquired in the future, the MARKAL-Turkey model is fed with data compiled from various national public and private companies, institutions and non-governmental organizations, and further enriched with the collaboration of AEA Technologies, who applied a similar MARKAL model for the Great Britain. The calibration is accomplished by comparing the 2006 results of the model with data of the same year. The resulting MARKAL-Turkey model is employed for working and analysis of scenarios pertaining to sectoral breakdown of carbon dioxide emissions, expected variations of emissions and emission reduction costs.

The MARKAL-Turkey model houses six main components: Primary resources, conversion technologies, energy carriers, demand technologies and final demand sectors. These main components can be observed in Figure 3.3 in further detail.

As mentioned before, the reference year of the MARKAL-Turkey model is set to 2006. The model runs in increments of five years, concluding in year 2051. In this setting, basic model variables are set to their realized values of year 2006 and hence, the model is not allowed to set the capacity levels, activity levels and resource supply amounts regarding 2006, freely. The outputs of this model was compared to the actual situation and after some calibration, the consensus is that the model reflected the year 2006 sufficiently good. The model with this parameter set is considered as the base scenario, which is taken as the basis in analysis of emission levels and related reduction costs, in comparison to other implemented scenarios. The definition and results of the base scenario are provided in Section 5.2.

The base scenario is not bound with any constraints on carbon dioxide emissions. Thus, in this base scenario, the model makes the capacity investment decisions solely

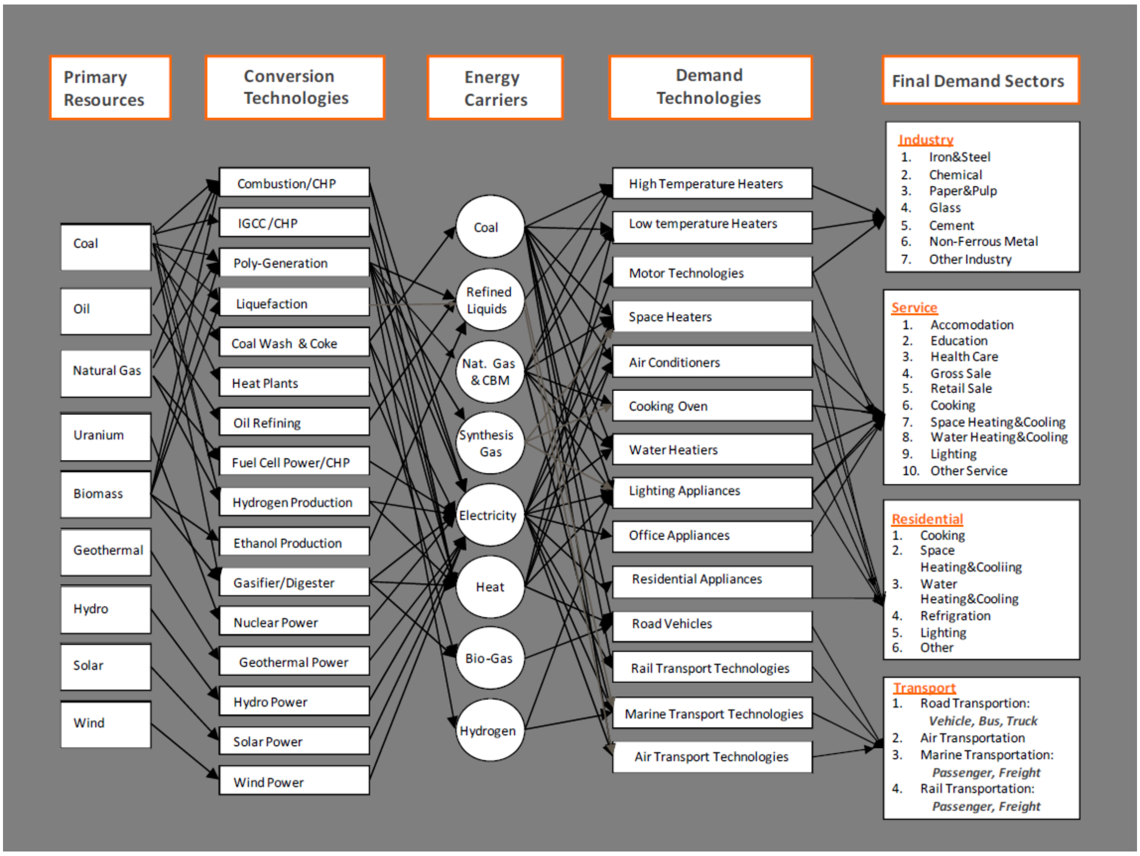

Figure 3.2. MARKAL-Turkey model components

by choosing technologies according to the aim of keeping the total system cost at minimum. When new constraints regarding carbon dioxide emission are introduced in other scenarios, the system costs vary accordingly in response. These interscenario differences in cost are labeled as “emission reduction costs”.

4. TECHNOLOGICAL DETAILS PERTAINING INDUSTRIAL ENERGY USE IN TURKEY

In the prevailing MARKAL based bottom-up national energy model, the technological details regarding production and processes of specific industrial sectors were not elaborated, while energy demand of many industrial branches were aggregated into the demand of “Other Industrial Use”, thereby explaining 65 per cent of the total industrial energy demand through this aggregate general sector. Additionally, the demand of the subsector “Other Industrial Use” was provided through generic demand technologies, which were not specialized pertaining to any specific industry and constitute a fuel use in parallel with the sum of other major industrial sectors included in the model.

Expanding the scope by increasing the number of specific industrial sectors represented in the MARKAL based bottom-up national energy model and detailing the specific cost, efficiency and demand parameters regarding these sectors in the model, in turn, improves the accuracy of the model: This way the demand and coverage of the generic subsector “Other Industrial Use” is decreased. The inputs, outputs and costs of the associated technologies are modeled with greater precision under the categorization of the newly specified industry sectors, reducing the effects of the generalization caused by the entity “Other Industrial Use”. Technologies introduced to the model are explained in Section 4.1.

The industrial sector regarding the manufacture of pulp & paper was already included in the previous model, nevertheless it is updated and detailed technologically within the scope of this work. The newly compiled technological technological parameters of this subsector are displayed in Subsection 4.1.3.

New industrial subsectors included in the model are manufacture of motor vehicles, manufacture of food & beverage and manufacture of textiles. New demand technologies feeding the projected demands of these subsectors are estimated and compiled according to the data specific to each introduced sector. The newly compiled technological parameters of these subsectors are displayed in Subsections 4.1.1, 4.1.2 and 4.1.4, respectively.

Accordingly, with the addition of these industrial sectors and with the major update of the pulp & paper industry, the industrial component of the revised bottom-up national MARKAL model comprises eight of the nine most energy-consuming industrial sectors in Turkey, as depicted by the TUIK [55]. Nonetheless, the more recent and thorough OSD benchmark projects a much higher level of industrial activity and resulting energy needs for the automotive industry than the accounted demand in TUIK data [56]. As a result, the reputedly tenth most energy-consuming automotive industry turns out to be seventh according to the OSD projection, and the industries embraced in this work constitute the nine largest industrial sectors in Turkey, in terms of energy consumption. Further details regarding industrial demands can be found in Section 4.2.

4.1. Specifically Covered Energy–consuming Industrial Subsectors

In order to compile the energy consumption and demand technology data regarding the introduced and covered industrial subsectors, a reference corporation or a group of reference corporations in each field are surveyed. Chosen reference corporations are well-established and sufficiently represent their sector: They have good reputations, considerable book values and significant market shares in their field of operation.

In order to obtain the mentioned technologically detailed energy data, confidentiality agreements have been signed and in compliance to these agreements, individual names of companies and some details regarding methodology and energy data are kept confidential.

4.1.1. Manufacture of Motor Vehicles

Turkish automotive industry has a significant place in a global scope. Turkey is placed sixteenth in the world in production of motor vehicles [57]. The leading twenty countries in manufacture of motor vehicles are given in Table 4.1. Moreover, Turkey is a regional powerhouse in automotive industry and exported 72 per cent of its motor vehicle production in 2009 [58]. Accordingly, the automotive industry is of vital importance in Turkish economy and consideration of its energy use is necessary in establishing an accurate model. The companies surveyed within the context of this work account for 25 per cent of the produced motor vehicles in Turkey and constitute Turkey's largest portion of motor vehicle export. Also, a complete picture of the consumed energy within the automotive industry is available through the OSD data [58].

In the Turkish automotive industry, mainly electricity and natural gas are utilized as energy sources. Breakdown of electricity and natural gas use with respect to departments in the Turkish automotive industry are displayed in Table 4.2.

As shown in Table 4.2, the paint department is where most intensive energy use occurs. The energy use in paint department involves heating of water to 55 °C for baths of surface cleaning, heating of air to 170 °C to be blown by drying ovens and keeping of temperature between 20 °C and 23 °C in application cabins. Other than these, there are cataphoresis baths where electricity flow through water is provided. For the most part, natural gas is used for heating of water to use in baths and in burners, where the air is heated and is then blown in drying ovens. Electricity is mainly used in cataphoresis baths. Other than that, energy for other basic machine work, movement and lighting are also supplied through electricity.

The body and press departments require energy to meet the demands of welding processes, cold working and pressing of the metal and also for cooling of metal. The electricity use is dominant in these departments, but natural gas is also used for some welding work.

The assembly, gearbox and chassis departments require a respectable amount of energy to drive the motors deployed in their industrial processes. Almost all work accomplished in these departments involves the use of automatic machinery or power hand tools, all of which are dependent on electricity. A significant amount of natural

Table 4.1. Top 20 countries in vehicle production, 2009 [57]

#	Country	Cars	Commercial vehicles	Total
1	China	10,383,831	3,407,163	13,790,994
2	Japan	6,862,161	1,072,355	7,934,516
3	USA	2,249,061	3,462,762	5,711,823
4	Germany	4,964,523	245,334	5,209,857
5	South Korea	3,158,417	354,509	3,512,926
6	Brazil	2,576,628	605,989	3,182,617
7	India	2,166,238	466,456	2,632,694
8	Spain	1,812,688	357,390	2,170,078
9	France	1,821,734	228,028	2,049,762
10	Mexico	939,469	617,821	1,557,290
11	Canada	822,363	667,288	1,489,651
12	UK	999,460	90,679	1,090,139
13	Czech Rep.	967,760	6,809	974,569
14	Thailand	305,250	663,055	968,305
15	Poland	819,000	60,186	879,186
16	Turkey	510,931	358,674	869,605
17	Italy	661,100	182,139	843,239
18	Iran	692,230	60,080	752,310
19	Russia	595,839	126,592	722,431
20	Belgium	510,300	12,510	522,810

Table 4.2. Breakdown of electricity and natural gas use in automotive industry

	Electricity (%)	Natural Gas (%)
Paint	33	75
Body	21	6
Press	6	2
Assembly	7	8
Engine	10	1.5
Gearbox	11	2.5
Chassis	7	1.5
Other	5	3
Total	100	100

gas is used in the assembly department where preheating of some metal parts occur prior to the assembly. Other natural gas use is required for heating of workspace, but this involves minuscule amounts in comparison.

When all energy demand of automotive industry is categorized by means of usage —in parallel with the underlying bottom-up MARKAL model— the end-demand technology percentages displayed in Table 4.3 are obtained.

Table 4.3. Energy demand breakdown in the automotive industry according to type

Use	Demand in MARKAL	Amount (%)
High Thermal Heat (HTH)	IAUH	54
Low Thermal Heat (LTH)	IAUL	17
Motor (MOT)	IAUM	17
Other (OTH)	IAUO	12

The energy demands of the automotive industry categorized by type —as high thermal heat, low thermal heat, motor and other— are defined in parallel to the rest of the MARKAL model at hand and are listed in Table 4.4 with their relevant parameters.

Table 4.4. Cost and efficiency parameters pertaining to the automotive industry

Technology	Definition	FIXOM	INVCOST	OUT(ENC)p
IAUHNGA00	Automotive HTH NGA	0.25	2.50	0.85
IAUHELC00	Automotive HTH ELC	0.23	2.30	0.9
IAULNGA00	Automotive LTH NGA	0.25	2.50	0.9
IAULELC00	Automotive LTH ELC	0.23	2.28	0.92
IAUMELC00	Automotive MOT ELC	0.14	1.40	0.925
IAUONGA00	Automotive OTH NGA	0.25	2.50	0.87
IAUOELC00	Automotive OTH ELC	0.23	2.30	0.9

The parameter FIXOM signifies the annual fixed operation and management cost and the parameter INVCOST signifies the annual total cost of investment in new capacity, both in million pound sterlings (value of year 2000) per PJ. The parameter OUT(ENC)p denotes the efficiency ratio in end-use per unit of energy input, such as electricity for industrial use (IELC) or natural gas for industrial use (INGA).

For instance, the technology IAUHNGA00 determines the high thermal heat type of demand in the automotive industry which is provided through use of natural gas for industrial use (INGA). In the context of this example, producing 0.85 energy units of high thermal heat output requires one equivalent unit of industrial natural gas input.

4.1.2. Manufacture of Food & Beverage

Though Turkey is not a global power in food & beverage industry, the exports of the Turkish food & beverage industry is about five per cent of the total Turkish export and they have been following a steady positive trend since 2003 [59].

The food & beverage industry encompasses a large number of sub-branches, such as fruit & vegetable processing, processed floury products, milk and milk products, confectionery, meat and poultry products, seafood operations, sugar production and refining, animal and vegetable fats, carbonated beverages, natural and mineral water bottling, alcoholic beverages and fodder production. The data employed in this study is compiled via the cooperation of a national conglomerate functioning in the milk and milk products, meat and poultry products, seafood operations, natural and mineral water bottling and fruit-based beverages sub-branches of the food & beverage industry. In some of these sub-branches, this company is the leader, both in terms of market share and amount produced.

Although there is some variation in the utilization of energy among various sub-branches, the primary consumption of energy is in the thermal processes. Boiling, frying, baking, simmering, pasteurization and steaming are the chief heating processes, whereas freezing and chilling are the main cooling processes. High-temperature boiling, deep-frying and pasteurization require the application of high thermal heat which can be supplied through either electricity or natural gas —but natural gas is dominantly preferred and used for high thermal heat generation. For baking, simmering and warming operations, application of low thermal heat is necessary, which again, can be supplied through either electricity or natural gas. For cooling purposes; fans, pumps, ventilators and mixers are utilized which function for the most part through electricity.

Table 4.5. Energy demand breakdown in the food & beverage industry according to type

Use	Demand in MARKAL	Amount (%)
High Thermal Heat (HTH)	IFBH	18
Low Thermal Heat (LTH)	IFBL	50
Motor (MOT)	IFBM	29
Other (OTH)	IFBO	3

Currently, in Turkey, 29 per cent of the total energy required by the food & beverage industry is supplied through electricity. The other 71 per cent is utilized through the consumption of natural gas. Energy demand breakdown of the food & beverage industry according to type of usage and technology parameters are displayed in Table 4.5 and Table 4.6, respectively.

Table 4.6. Cost and efficiency parameters pertaining to the food & beverage industry

Technology	**Definition**	**FIXOM**	**INVCOST**	**OUT(ENC)p**
IFBHNGA00	Food&Beverage HTH NGA	0.25	2.50	0.85
IFBLNGA00	Food&Beverage LTH NGA	0.20	2.00	0.9
IFBMELC00	Food&Beverage MOT ELC	0.14	1.40	0.925
IFBONGA00	Food&Beverage OTH NGA	0.23	2.20	0.87

4.1.3. Manufacture of Pulp & Paper

According to 2008 data, the anuual paper products production in the world accrues to about 391 million tons. Of this amount, 2.3 million tons are produced in Turkey. This amount puts Turkey in 25th position in production. Turkey consumes 4.3 million tons of paper products per year, thereby being the 16th largest consumer in the world [60]. As these statistics point out, both in terms of manufacture and demand, pulp & paper industry is a key Turkish industry.

Pulping is the process by which the fibers in wood are separated and treated to produce a pulp. In high-yield mechanical pulping, wood is subjected to shear and compression forces in order to separate the fibers. Recycled paper is re-pulped primarily through mechanical treatment. Most pulp is pumped as a slurry directly to an integrated paper or paperboard facility, where it may be mixed with other pulps, recycled fiber, or fillers such as clay before going into paper production [61]. The production of paper involves preparing the stock from pulp, forming a sheet, dewatering and drying, and sometimes coating the paper. All paper production processes have three basic elements: wet end, press section, and drying section.

The companies surveyed in the accumulation of the pulp & paper industry data function in a wide array of sub-branches (manufacture of toilet paper, handkerchiefs, paper towels, tissues, packaged tissues and other paper products for commercial and industrial use) and account for the 29 per cent of the Turkish pulp & paper industry, in terms of energy consumption.

Table 4.7. Energy demand breakdown in the pulp & paper industry according to type

Use	Demand in MARKAL	Amount (%)
Drying (DRY)	IPPD	64
Motor (MOT)	IPPM	35
Other (OTH)	IPPO	1

In the pulp and paper industry, electricity represents about 36 per cent of the energy source. Another 36 per cent share of the energy demand of pulp and paper industry is supplied through natural gas and the remaining 28 per cent is supplied through steam.

The vast majority of the utilized electricity is consumed by pulping and paper-making machinery, where wet pressing and calendering processes take place. The remaining two to three per cent of electricity is used in utility services, such as lighting. The steam energy is used in preparing the boilers and drying the paper, between wet pressing and calendering processes for the most part. Similarly, natural gas is employed is activating the burners and blowing hot air on paper in drying processes. Less than one per cent of the natural gas consumption is due to area heating. Energy demand breakdown in the pulp & paper industry according to type of usage and technology parameters are displayed in Table 4.7 and Table 4.8, respectively.

Table 4.8. Cost and efficiency parameters pertaining to the pulp & paper industry

Technology	**Definition**	**FIXOM**	**INVCOST**	**OUT(ENC)p**
IPPDSTM00	Pulp&Paper DRY STM	0.20	2.00	0.9
IPPDNGA00	Pulp&Paper DRY NGA	0.25	2.50	0.85
IPPONGA00	Pulp&Paper OTH NGA	0.25	2.50	0.87
IPPMELC00	Pulp&Paper MOT ELC	0.14	1.40	0.925
IPPOELC00	Pulp&Paper OTH ELC	0.23	2.30	0.9

4.1.4. Manufacture of Textiles

The energy consumption in the textiles industry is examined in two production systems either of which necessitate integral and complex manufacturing processes exemplifying the sectoral energy consumption amounts and patterns, which is the issue of interest in this study. The first production system comprises the knitting and weaving processes which together compose the manufacture of the fabric. The second one, usually a follow-up to the first system, is named finishing processes, in general and may contain one or more of many diverse processes such as scouring, bleaching, singeing, calendering, mercerising, shrinking, desizing, raising, dyeing and printing; depending on the type of the fabric and aim of usage. Due to the existence of uncountable small and medium sized businesses and various types of sub-branches in the textiles sector, it is difficult to assess the market shares and production shares pertaining to a company operating in the textiles sector. But it can be stated that the corporation which has assisted in the detailing of the data pertaining to the textiles industry possesses the production facilities with the largest capacity available in Turkey and is one of the major textiles exporters. Besides, the corporation consists of multiple companies, operating in various stages of the textiles manufacture, from fiber production to manufacture of fabrics, and to manufacture of end products within a wide spectrum.

Table 4.9. Energy demand breakdown in the textiles industry according to type

Use	Demand in MARKAL	Amount (%)
Drying (DRY)	ITXD	58
Low Thermal Heat (LTH)	ITXL	21
Motor (MOT)	ITXM	13
Other (OTH)	ITXO	8

Comparing the fabric manufacture processes and finishing processes, type of energy employed and aim of usage differs significantly. Most of the energy in knitting and weaving processes is supplied through electricity. About sixty per cent of the electricity consumed in these processes accompanies air consumption which is used for the cooling of machinery in operation. Another significant portion of electricity consumed (about

25 per cent) is directly employed for the operation of knitting and weaving machinery. The other electricity consumption in this system is due to area cooling, knitting preparation and lighting. Also, one-third of the energy demand is met through steam energy which can be obtained through natural gas, coal or geothermal energy. Two-third of the employed steam energy in fabric manufacture processes is employed in drying and warming of water, whereas the other one-third is utilized in heating of the work area.

Table 4.10. Cost and efficiency parameters pertaining to the textiles industry

Technology	**Definition**	**FIXOM**	**INVCOST**	**OUT(ENC)p**
ITXDSTM00	Textiles DRY STM	0.20	2.00	0.9
ITXLELC00	Textiles LTH ELC	0.23	2.28	0.92
ITXLNGA00	Textiles LTH NGA	0.25	2.50	0.9
ITXMELC00	Textiles MOT ELC	0.14	1.40	0.925
ITXOSTM00	Textiles OTH STM	0.23	2.20	0.87

In the finishing process systems, steam energy is used extensively, mostly for drying and steaming. Also, a small portion of the steam energy is employed in space heating. Natural gas is used in providing low thermal heat in various finishing processes, and also in print machinery, in order to allow drying of printed fabrics in a slow fashion. Energy demand breakdown according to type of usage and technology parameters are displayed in Table 4.9 and Table 4.10, respectively.

4.2. Energy Demands of Industrial Sectors

Both current and future energy demands of industrial subsectors are extraneous to the MARKAL model, they need to be estimated and inputted to the model by the user. As aforementioned, the previous work comprised the industrial sectors regarding to manufacture of chemicals (ICH), cement (ICM), glass (IGL), iron & steel (IIS), non-ferrous metals (INF), pulp & paper (IPP) and other industrial use (IOI). The demands regarding these sectors were derived with application of linear regression to a combination of data from TUIK, EIE and AEA technologies. The preset demands right before the start of this work are displayed in Table 4.11 and Figure 4.2.

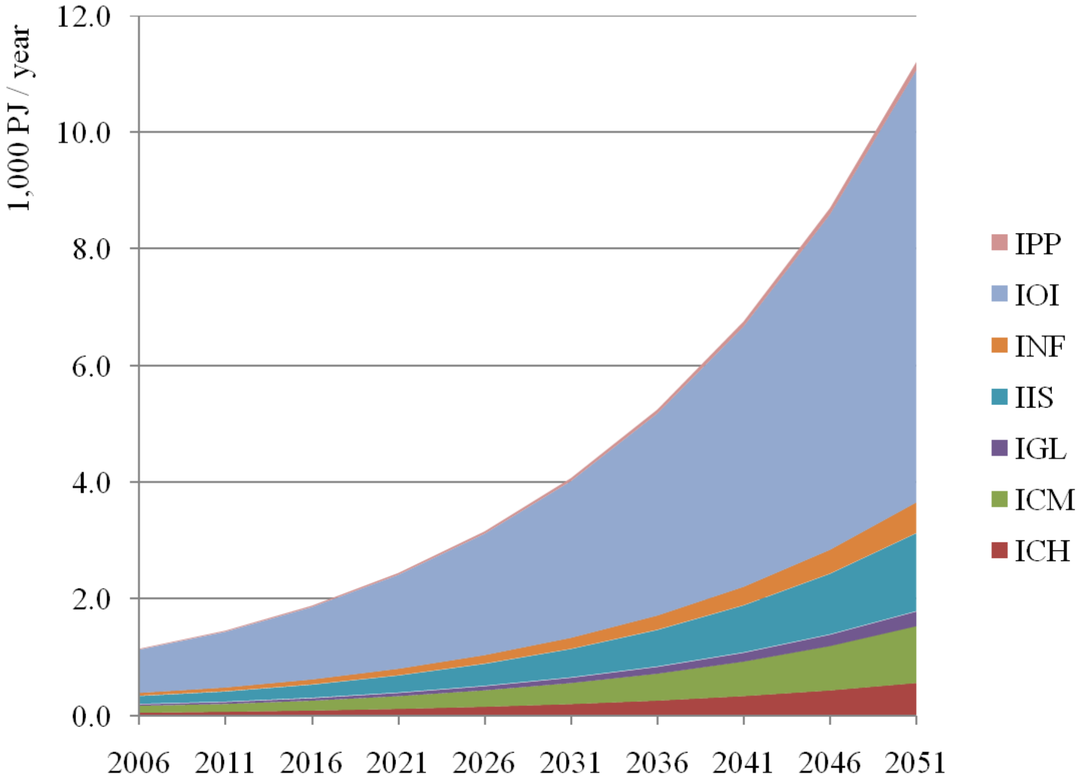

Figure 4.1. Demands of industrial sectors, as applied in the previous work

The introduced and updated industrial sectors —manufacture of motor vehicles (IAU), food & beverage (IFB), pulp & paper (IPP) and textiles (ITX)— also contribute their energy demands to the model (these demands were previously encapsulated within the demand label "Other Industrial Use" (IOI)). Hence, the amount of the generic "Other Industrial Use" (together with the utilization of the energy processes and technologies regarding the delivery of this demand) declines which enhances the accuracy and quality of this model, as outlined in the preamble of Chapter 4. Also, the total demand by industry is consistent with previous work, both in 2006 and also in the future timespan of the model.

The energy demand regarding manufacture of food & beverage (IFB), pulp & paper (IPP) and textiles (ITX) industries are determined in light of the TUIK data [55], as one cannot evaluate the demand of these sectors with regard to a few reference companies, due to the unmeasurable real market shares and due to the operation of numerous minuscule establishments in various sub-segments of these sectors.

Table 4.11. Demands of industrial sectors, as applied in previous work (in PJ/a)

	2006	2011	2016	2021	2026	2031	2036	2041	2046	2051
ICH	56	72	94	122	158	204	263	339	436	562
ICM	120	135	169	219	283	361	462	594	763	977
IGL	25	32	42	55	71	91	118	152	195	251
IIS	133	172	223	290	375	483	623	803	1035	1333
INF	53	68	88	115	148	191	247	318	410	528
IOI	741	956	1242	1612	2083	2688	3466	4467	5756	7414
IPP	14	18	24	31	40	52	67	86	110	142
TOTAL	1143	1455	1883	2442	3156	4070	5245	6759	8705	11208

The energy demand pertaining to the manufacture of motor vehicles is estimated through the OSD data [56]. In inferring the total demand of the automotive industry, the lower heat value for each type of fuel is multiplied with the amount of that type of fuel consumed by the automotive industry, and the resulting energy demands for each type of fuel are added up.

In order to estimate the energy demand growth rates of the considered industrial subsectors, expert opinions from each industrial branch are utilized, while the total demand of the industry is kept in conformity with the total industrial demand used in the previous work. The energy demands specific to each industrial subsector considered can be seen in Table 4.12 and Figure 4.2, where the newly introduced sectors and their demands are shown on the top.

The changes in the growth rates of iron & steel industry and the non-ferrous metals industry are most noticeable, where the iron & steel industry exhibits a slower growth rate and the non-ferrous metals industry displays a rapid expansion, in comparison to the estimations followed in the previous work. As a result, the energy demand of the non-ferrous metals industry exceeds the demand of the iron & steel industry by 2046.

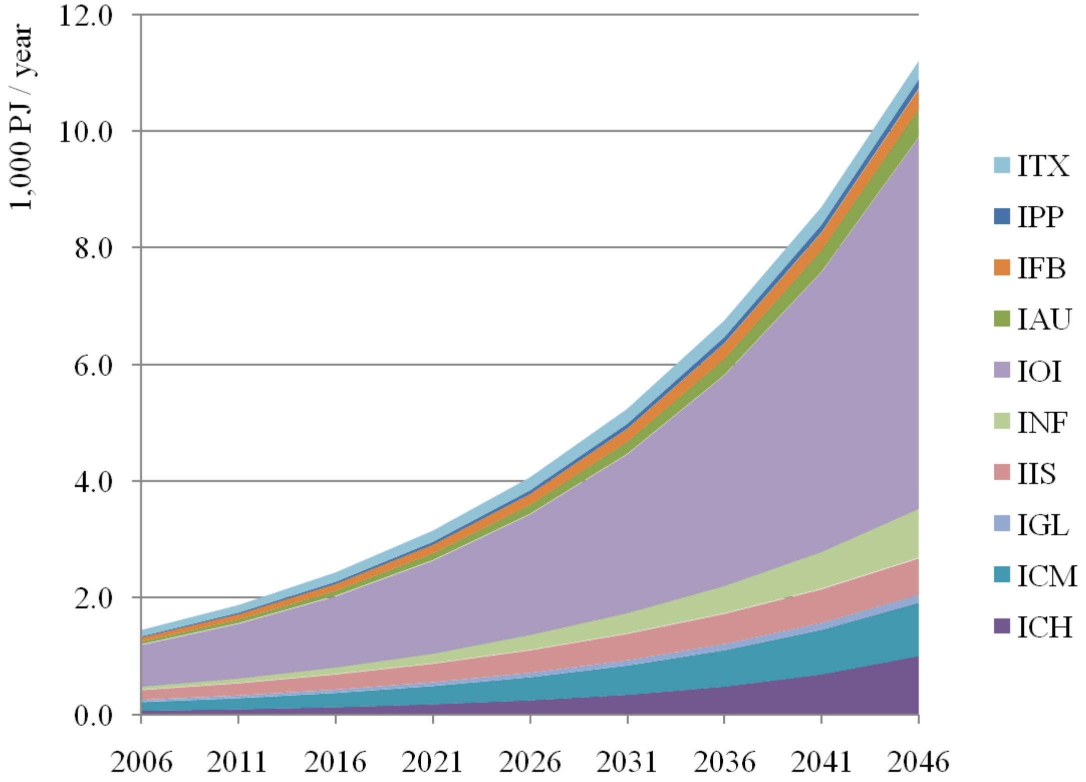

Figure 4.2. Energy demands of all industrial sectors considered

While the generic subsector “Other Industrial Use” is still dominant, its amount has been reduced by 26 per cent in 2006 and consecutively, its share in industrial energy demand recedes from 65 per cent to 48 per cent, which is considered to be a significant improvement.

Table 4.12. Energy demands of industrial sectors considered (in PJ/a)

	2006	2011	2016	2021	2026	2031	2036	2041	2046	2051
IAU	37	48	65	87	118	159	212	283	376	496
ICH	56	73	97	133	183	250	343	481	690	1003
ICM	120	150	191	246	313	395	501	624	763	912
IFB	59	75	96	123	152	185	225	265	303	337
IGL	25	33	43	53	63	75	90	108	125	143
IIS	133	166	208	260	316	386	455	520	577	627
INF	53	65	86	124	175	267	357	478	639	848
IOI	548	714	937	1217	1593	2064	2719	3607	4795	6364
IPP	16	21	28	37	49	64	84	108	133	160
ITX	96	109	130	163	193	225	259	286	305	319
TOTAL	1143	1455	1883	2442	3156	4070	5245	6759	8705	11208

5. SCENARIOS EMPLOYING POLICIES FOR REDUCING THE CARBON FOOTPRINT

5.1. Scenario Definitions

The policies investigated in the scenarios seek the reduction in total CO_2 emission amount rather than seeking mitigation of the CO_2 emission caused by the industrial sector only. There are three reasons for this; firstly, a lot of the CO_2 emissions triggered by the industrial energy consumption occur before the delivery of the secondary energy types —e.g., electricity and steam— to the industry, at the time of their production. It can be argued that one could find out the share of such energy consumed by the industrial sector and the amount of the corresponding CO_2 emissions. Still, this is another source of ambiguity, as there is a number of research —e.g., Ordorica-Garcia et al. [12]— charging all of the CO_2 emissions caused by secondary energy production to the account of the industrial sector under the energy production (or power) industry. Hence, it is not easy to precisely determine how to account for the emissions caused by the industry. Secondly, even if a convention for calculating the amount of CO_2 emission caused by the industry were to be agreed upon, the emission caused by the industry in each scenario would come roughly to the same percentage of the total emissions —which is the share of the industry in total demand— since no policy specific to any industrial subsector is applied in this work and since the industrial energy demands correspond to the same portion of the total energy demand in each scenario. Thirdly, the national policy that the developed model and the analysis conducted aims to support is concerned with managing and reducing overall national greenhouse gas emissions and not just those of the industrial sector.

As explained in detail in Section 3.1, MARKAL is primarily an optimization approach and the MARKAL model is geared to meet the defined energy demands while maintaining minimal total system costs. The model is calibrated to reflect the real conditions in 2006 at its reference year (2006), as described in Section 3.3. The base scenario takes these realized values regarding demands, technology parameters and resource availability amounts into account, as any other scenario. Also, all the industrial improvements detailed in Chapter 4 are included in the base scenario.

The only two additional constraints applied in the base scenario are capacity and timing restrictions in the selection and deployment of nuclear power and CCS investments, which in turn prohibit unhindered and full capacity use of these technologies. In other words, after the year 2006, the model is free to do any capacity investments, fuel switches and technological choices as it sees fit for minimizing the total system cost —other than the two constraints regarding use of nuclear power and CCS technologies.

Each case involving a policy application —including the base scenario despite the fact that it does not involve an active energy policy— branches out one more time, in order to further analyze two factors, namely, permitted maximum deployment rate for the nuclear power generation capacity and the permitted maximum installation rate of the CCS technology. Each of these factors have "fast" and "slow" states and their respective definitions are given in the following paragraphs. Hence, each case of policy application comprises four scenarios with each combination of these states and these will be briefly labeled as "fast nuclear, fast CCS (FF)", "fast nuclear, slow CCS (FS)", "slow nuclear, fast CCS (SF)" and "slow nuclear, slow CCS (SS)" throughout the remainder of the text.

The "high" state for nuclear power development instructs the model to make available nuclear power generation at least six per cent of all available electricity production activity in 2016 and to permit increasing its minimum share in the following time periods as follows: 12 per cent by 2021, 15 per cent by 2026, 18 per cent by 2031, 21 per cent by 2036, 24 per cent by 2041, 27 per cent by 2046 and 30 per cent by 2051. The "low" state, on the other hand, limits the newly-installed nuclear power capacity to be at most 1GW per five years. For both of the "high" and "low" states, nuclear power generation is not allowed before the year 2016.

The "high" state for CCS installation requires that at least three per cent of the coal-based electricity production activity employ CCS technology in 2016. This minimum share increases through the planning horizon as follows: Six per cent by 2021, nine per cent by 2026, 12 per cent by 2031, 15 per cent by 2036, 21 per cent by 2041, 27 per cent by 2046 and 30 per cent by 2051. In the "low" state, the CCS technology introduction is delayed to 2036 and the share of CCS in coal-based electricity production is at least two per cent in 2036, at least four per cent by 2041, at least six per cent by 2046 and at least eight per cent by 2051. The CCS technology use is not possible before 2016 in the "high" state" and not before 2036 in the "low" state.

Note that, in "high CCS" scenarios, it is possible that the CCS installed technology does have a smaller share than the defined minimum share of coal-based electricity production in "breakdown of the primary energy resource consumed in electricity generation" figures (e.g., Figures 5.3.1.3 and 5.4.1.3). That is because of the efficiency of CCS installed electricity production processes: For the same output of electricity (worth 1 PJ of energy), CCS installed technology consumes 2.5–3 units of coal, whereas current technology consumes 3–9 units of coal —getting closer to nine units when coal-based electricity production increases.

After the examination of the base scenario family, the policy involving a general constraint on the amount of total CO_2 emissions is examined. In this policy, the constituents cannot choose to emit CO_2 freely by paying its worth. The policy forces the system to emit less and make smart fuel and technology switches while maintaining minimal cost. The constraint set on the amount of general CO_2 emissions aims to reduce the level of total CO_2 emissions caused by a certain percentage, in comparison to the unconstrained emission levels in the base scenario. In every case, the constraint is designed to come into effect from 2016 onwards. In this study, five levels of percentage emission reduction are experimented with: 10 per cent, 20 per cent, 30 per cent, 40 per cent and 50 per cent, respectively —all with respect to the level of total emissions in the corresponding base scenario.

Then, a policy family of tax applications to discourage CO_2 emissions are investigated. This policy family assigns and charges a certain amount of tax (or penalty)

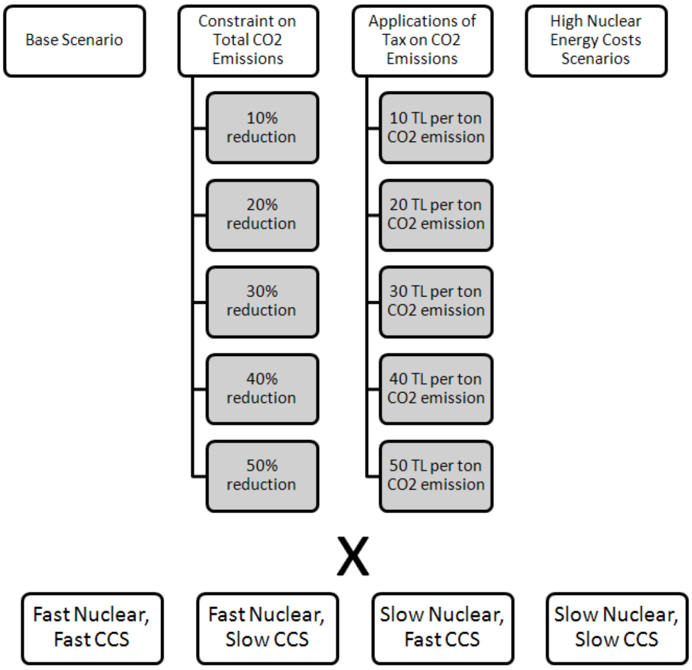

Figure 5.1. The scenarios studied

for each unit of emitted CO_2, while not directly restricting CO_2 emissions. In other words, it is left to the optimization process to decide whether to reduce CO_2 emissions (by opting for more expensive but less-emitting technologies) or to accept higher level of emissions and bear the associated cost (penalty). The system will only switch fuel sources or invest in new technologies if it can profit from this decision, within the lifespan of the model. Within this group of scenarios, five levels of tax are assessed: 10 TL per ton of CO_2 emission, 20 TL per ton of CO_2 emission, 30 TL per ton of CO_2 emission, 40 TL per ton of CO_2 emission and 50 TL per ton of CO_2 emission.

In Sections 5.2–5.4.1, three families of scenarios are studied —the base scenario and variants, scenarios constraining the amount of CO_2 emissions directly and scenarios where tax per metric ton of emitted CO_2 is applied. Under the subsections of each of these sections, individual members of these scenario families are studied. Figure 5.1 exhibits a scenario tree, listing every scenario examined in this study. Subsections discussing the scenarios feature two figures each, detailing the breakdown of primary energy use and the breakdown of energy utilized in electricity production. In these breakdown figures, energy sources having a share larger than 10 per cent in a certain period are labeled accordingly. Further analysis and comparison of the scenarios in terms of system costs and CO_2 emission is conducted in the last subsection, for each of the following three sections. Additionally, in the Section 5.5, two scenarios employing high nuclear energy costs are evaluated. The last section of this chapter, Section 5.6, briefly discusses the "best scenario" both in terms of carbon emissions mitigation and being cost–efficient, at the same time.

5.2. The Base Scenario and Variants

5.2.1. The Base Scenario – No Nuclear, No CCS

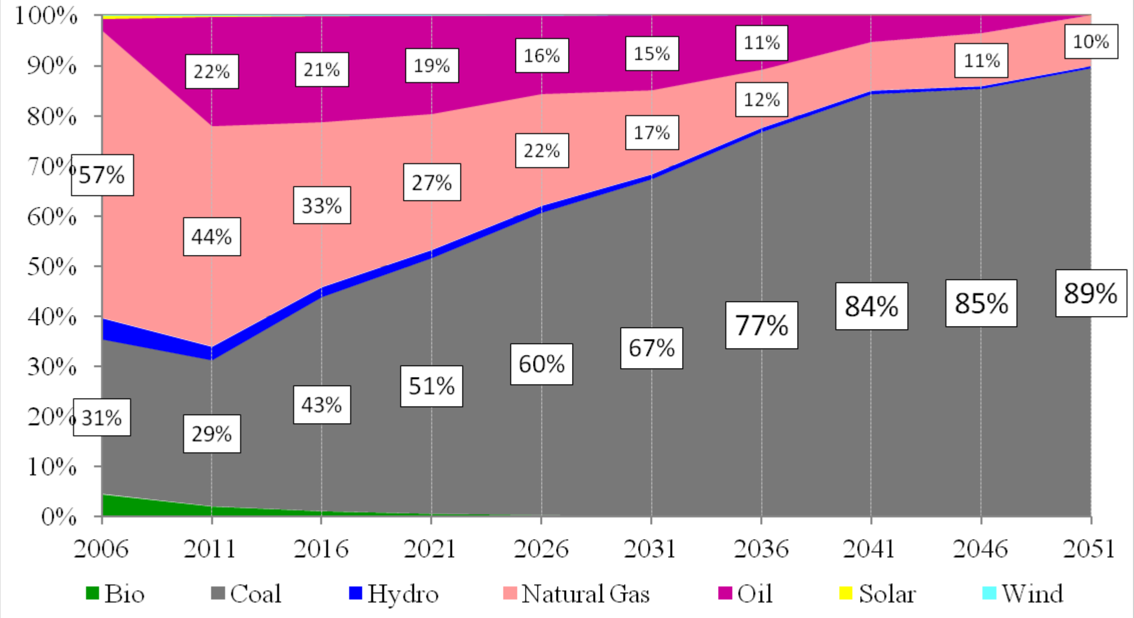

Figure 5.2. Breakdown of the primary energy resource consumption in the base scenario, no nuclear, no CCS

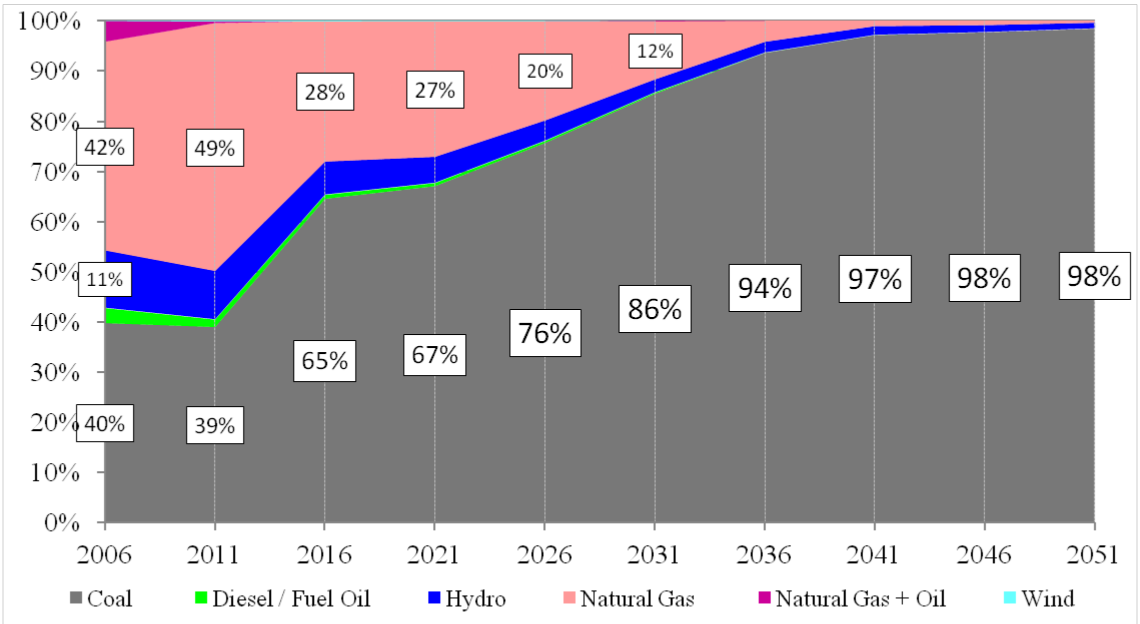

Figure 5.3. Breakdown of the primary energy resource consumed in electricity generation in the base scenario, no nuclear, no CCS

5.2.2. The Base Scenario, Fast Nuclear, Fast CCS

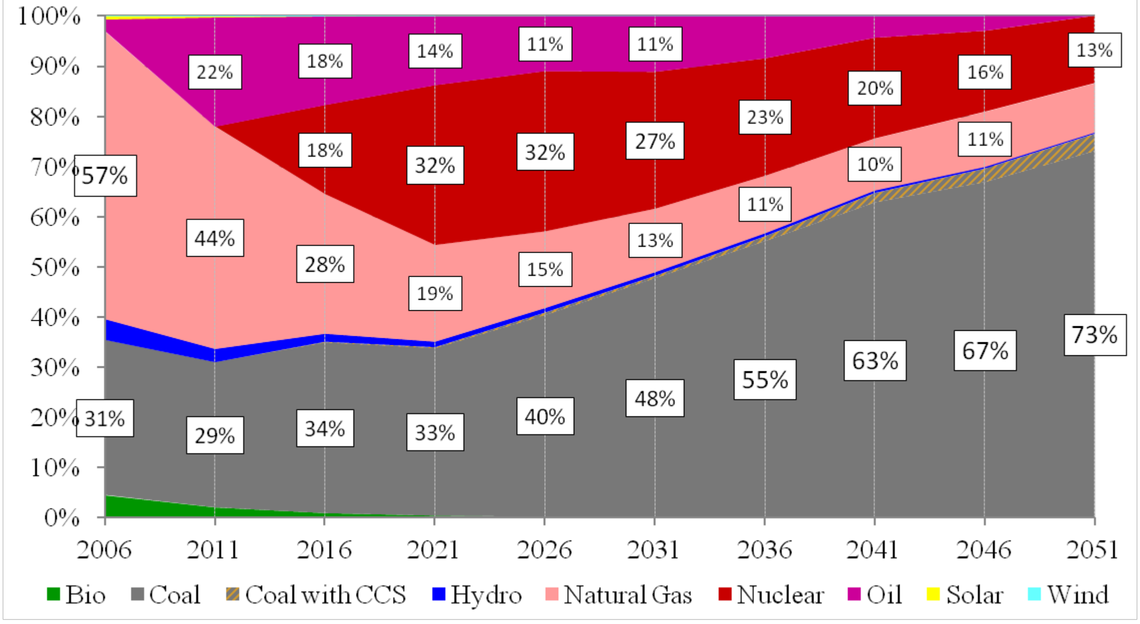

Figure 5.4. Breakdown of the primary energy resource consumption in the base scenario, fast nuclear, fast CCS case

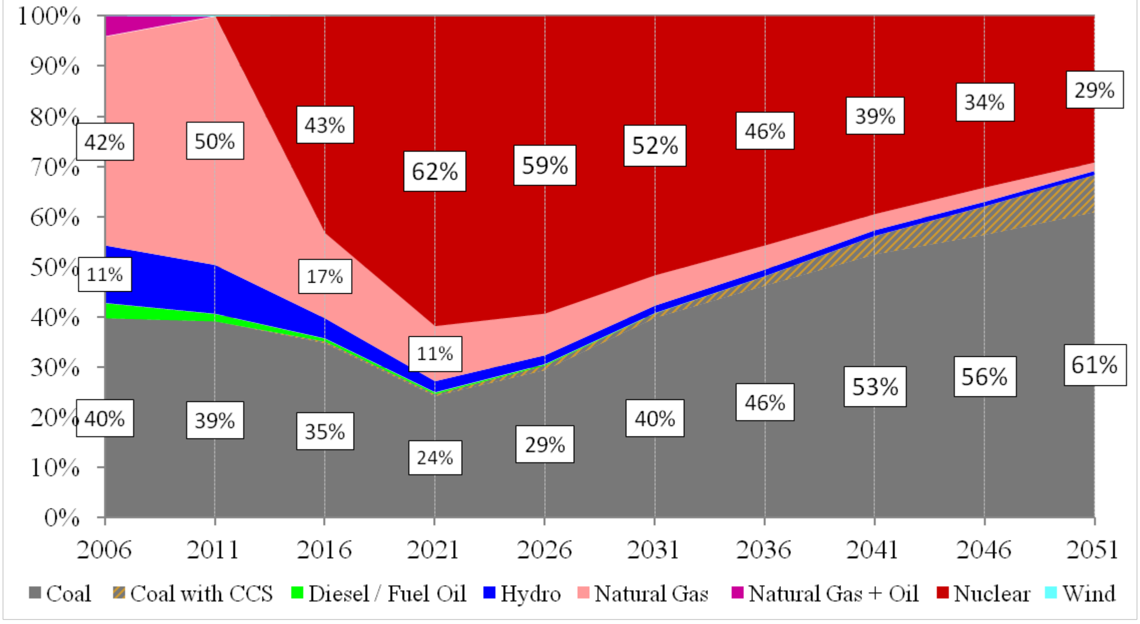

Figure 5.5. Breakdown of the primary energy resource consumed in electricity generation in the base scenario, fast nuclear, fast CCS case

5.2.3. The Base Scenario, Fast Nuclear, Slow CCS

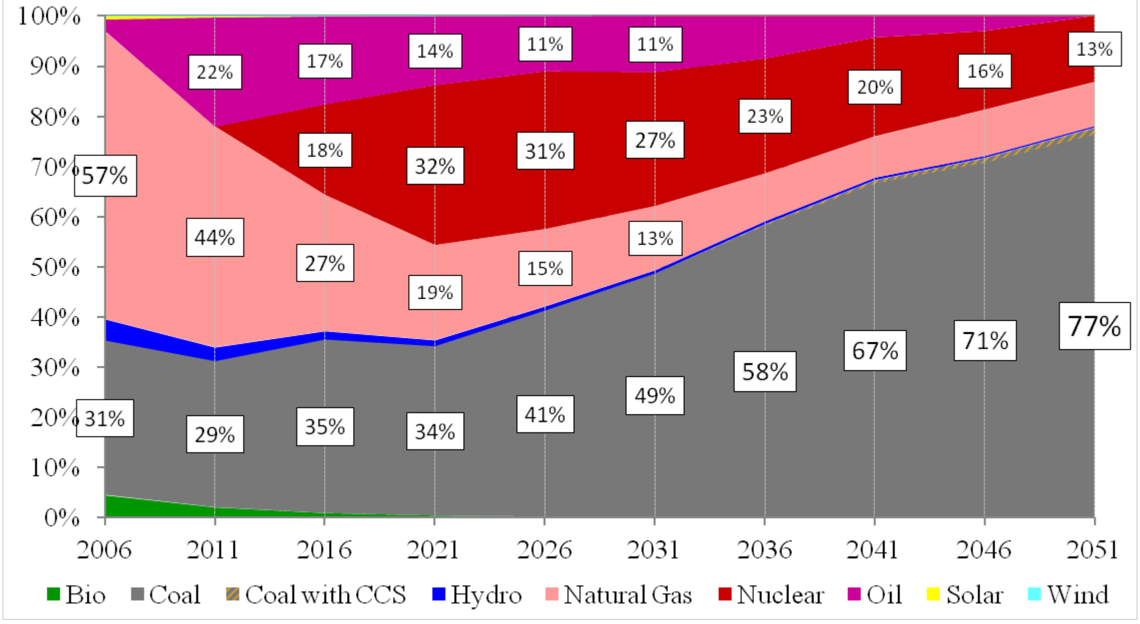

Figure 5.6. Breakdown of the primary energy resource consumption in the base scenario, fast nuclear, slow CCS case

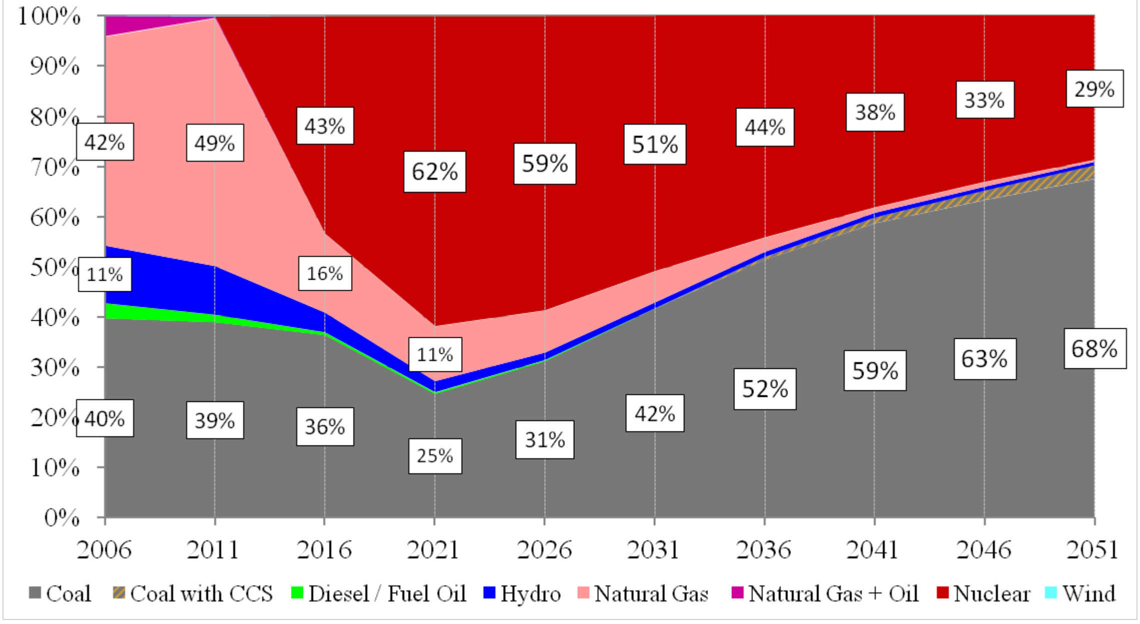

Figure 5.7. Breakdown of the primary energy resource consumed in electricity generation in the base scenario, fast nuclear, slow CCS case

5.2.4. The Base Scenario, Slow Nuclear, Fast CCS

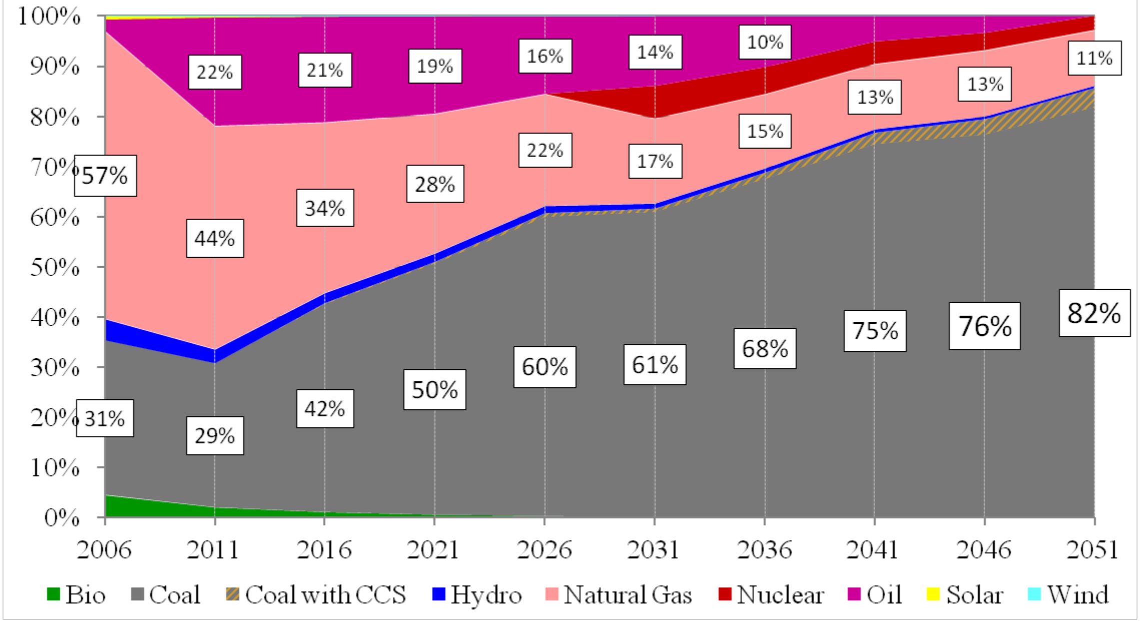

Figure 5.8. Breakdown of the primary energy resource consumption in the base scenario, slow nuclear, fast CCS case

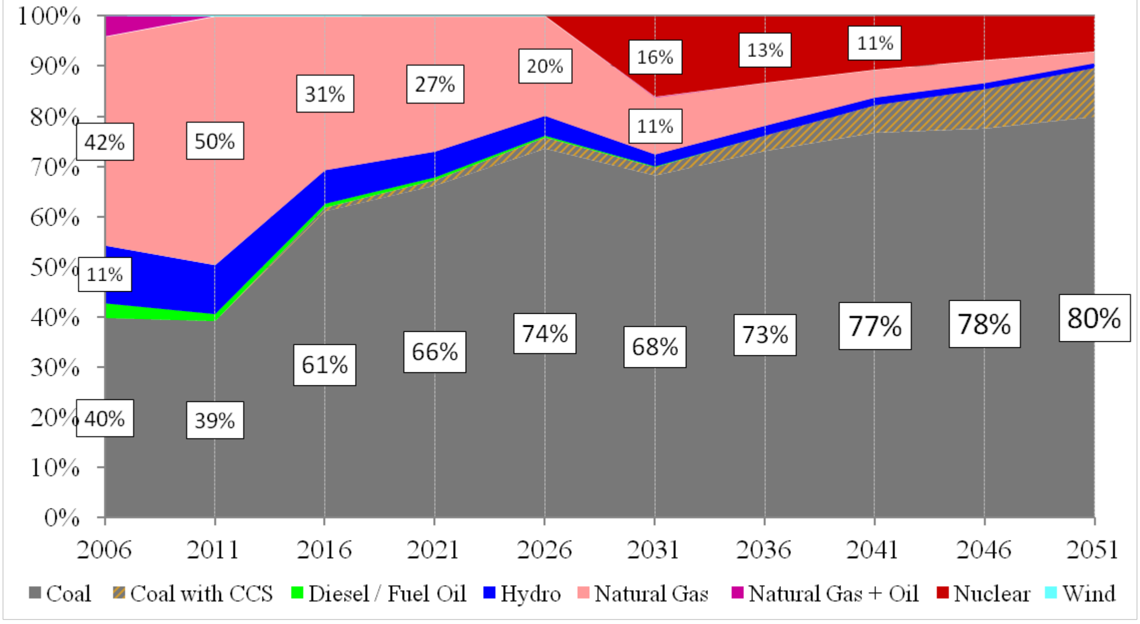

Figure 5.9. Breakdown of the primary energy resource consumed in electricity generation in the base scenario, slow nuclear, fast CCS case

5.2.5. The Base Scenario, Slow Nuclear, Slow CCS

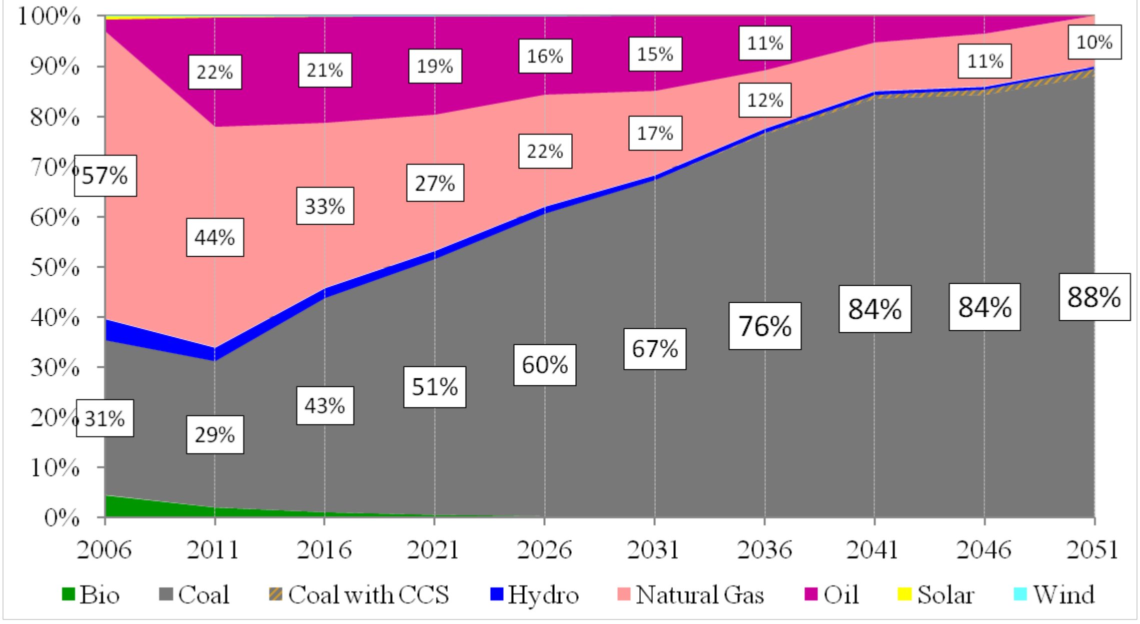

Figure 5.10. Breakdown of the primary energy resource consumption in the base scenario, slow nuclear, slow CCS case

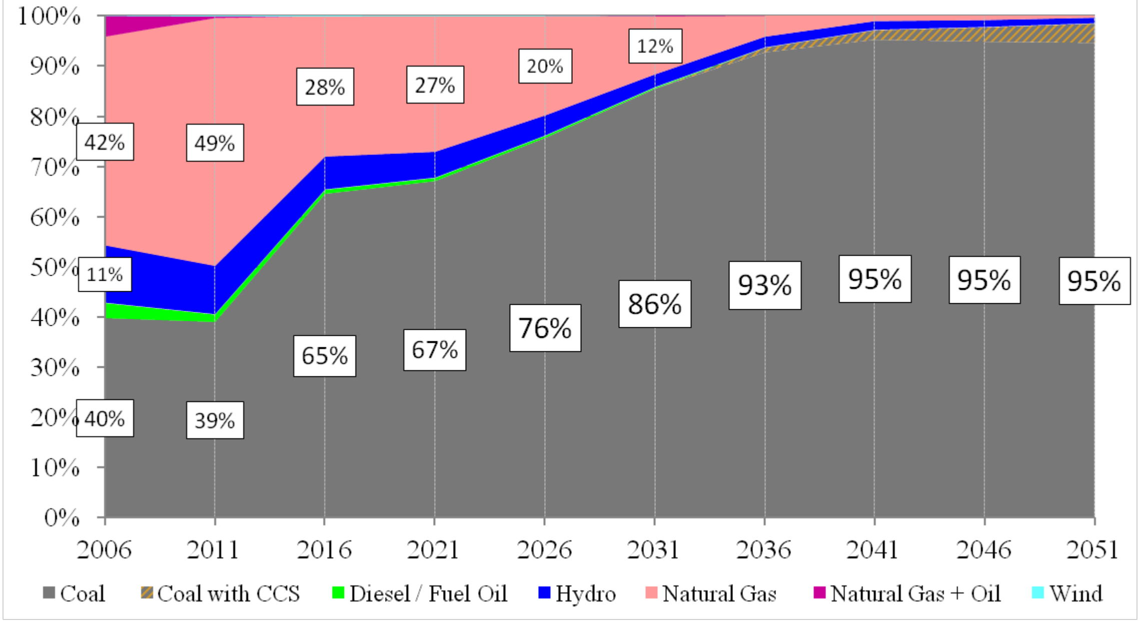

Figure 5.11. Breakdown of the primary energy resource consumed in electricity generation in the base scenario, slow nuclear, slow CCS case

5.2.6. Comparison and Analysis of Scenarios in the Base Group

Although additional nuclear capacity has no upper limit in fast nuclear scenarios, in all scenarios considered, coal is still dominant and increasing in share as time progresses. That is because there is no constraint regarding CO_2 emissions and the model makes only the minimum nuclear investment to fulfill the minimum deployment level limitations, especially in the "fast" nuclear scenarios. Also, the model invests in CCS installment only because of the minimum requirements.

Common in all these scenarios, one can see that without an active emission policy, coal dominates heavily both as a primary energy source and as a fuel in electricity production all through the planning horizon, maintaining the status quo.

Table 5.1. Total system cost and emissions in the base scenario group

Scenario	Cost (M TL/a)	CO_2 (kt/a)
BASIS	73,182	262,451
BASIS_FF	73,492	256,236
BASIS_FS	73,254	258,471
BASIS_SF	73,516	259,564
BASIS_SS	73,258	263,037

Table 5.1 shows the average annual cost and emission amount associated with each scenario. As expected, the total system cost increases with additional technology investment constraints, even though the increase is not very significant. The forced use of the less-emitting nuclear and CCS technologies leads to some minor reductions in the emissions amount, with the exception of the "slow nuclear, slow CCS" scenario where the change is insignificant, but features an increase in emissions.

5.3. Scenarios Constraining CO_2 Emissions Directly

5.3.1. The 10 Per Cent Reduction Scenarios

As portrayed in Figures 5.3.1.1 and 5.3.1.1, in the 10 per cent emissions reduction scenario, the nuclear power investments are moderate, despite the fact that there is no upper limit defined in “fast nuclear” scenarios. It can also be seen that nuclear energy captures most of the share of natural gas until the year 2031. After 2031, the share of the nuclear energy decreases while coal energy consumption is on the rise. The CCS investments are only due to the fulfillment of the minimum CCS investment constraints. The diminishing oil consumption allows the share of coal use to increase, while keeping total carbon emissions in compliance with the scenario requirement.

In the “fast nuclear, slow CCS” scenario (Figures 5.3.1.2 and 5.3.1.2), the share of coal consumption after the year 2031 is about 10 per cent lower than that of in the “fast nuclear, fast CCS” scenario. This may be explained through the limitation to the CCS investments. Since there is less CCS activity, coal consumption at the same levels cause more carbon emissions. The increasing share of the nuclear energy consumption moderates the amount of carbon emissions.

In the scenarios where nuclear investments are limited (the slow nuclear scenarios), the energy breakdown figures are very similar, independent of the CCS investment factor —as shown in Figures 5.3.1.3, 5.3.1.3, 5.3.1.4 and 5.3.1.4. The nuclear energy consumption is limited, and it provides one-third of the energy used in electricity generation, by the year 2051. Both in the “fast CCS” and the “slow CCS” scenarios, the coal consumption portrays a steady increase. The only difference between these two scenarios is the amount of CCS investment. The lower CCS investment levels in the “slow CCS scenario” results in increased nuclear energy usage.

5.3.1.1. The 10 Per Cent Reduction, Fast Nuclear, Fast CCS Scenario.

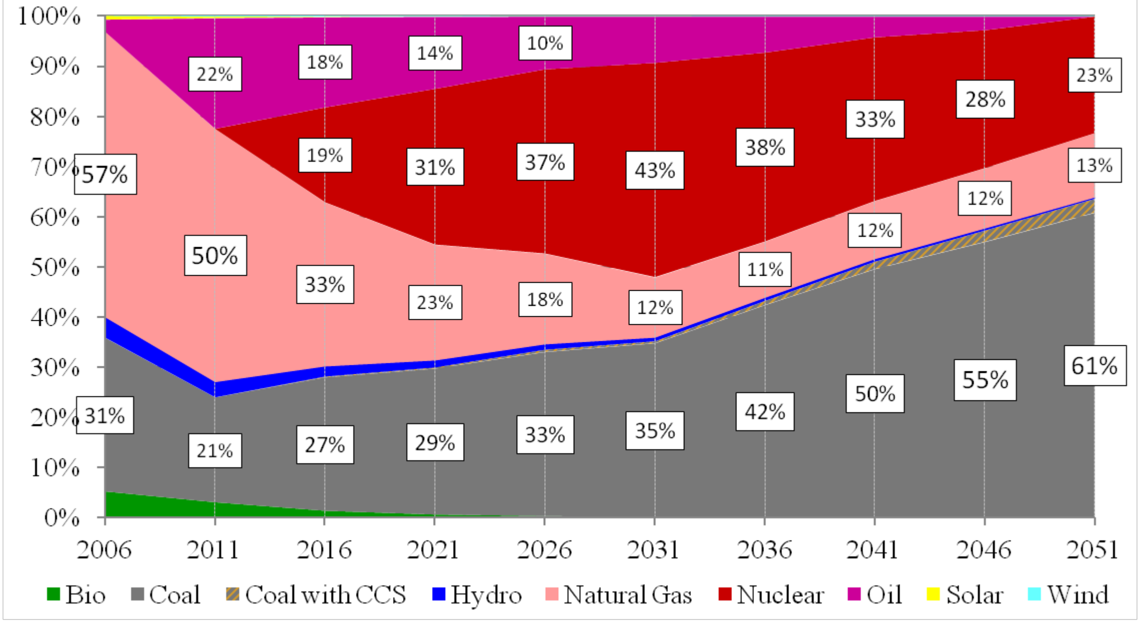

Figure 5.12. Breakdown of the primary energy resource consumption in the 10 per cent reduction, fast nuclear, fast CCS case

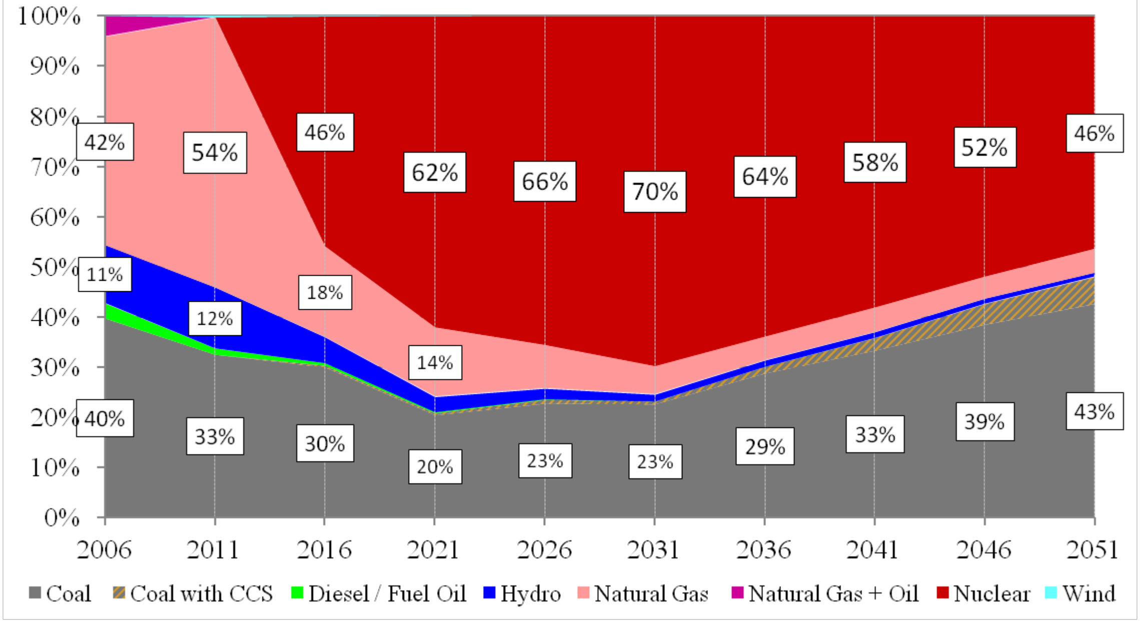

Figure 5.13. Breakdown of the primary energy resource consumed in electricity generation in the 10 per cent reduction, fast nuclear, fast CCS case

5.3.1.2. The 10 Per Cent Reduction, Fast Nuclear, Slow CCS Scenario.

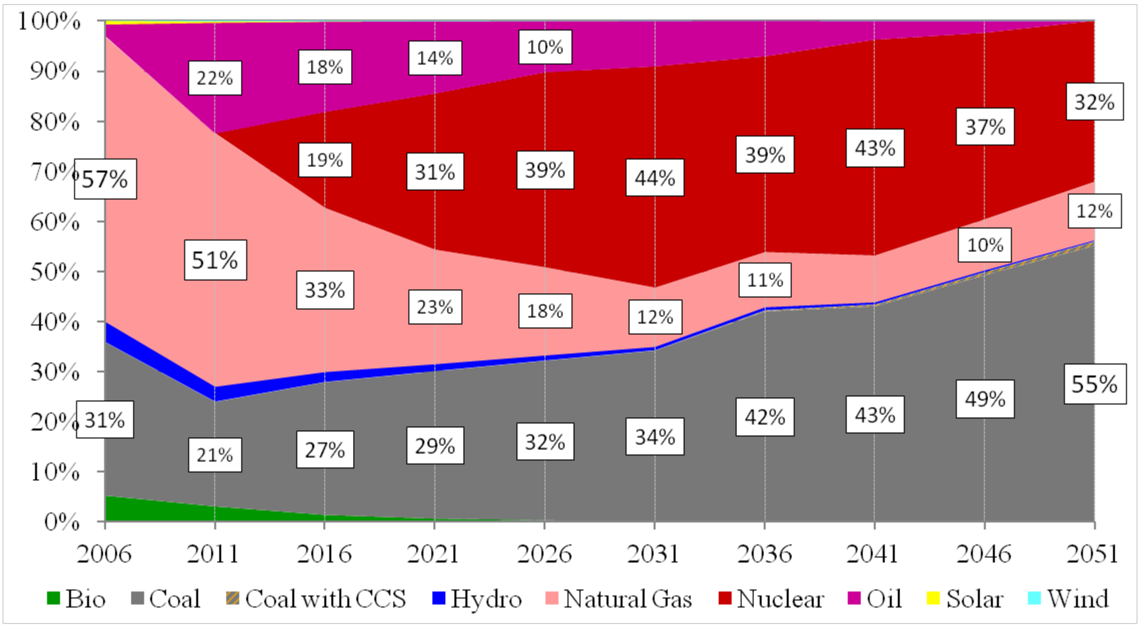

Figure 5.14. Breakdown of the primary energy resource consumption in the 10 per cent reduction, fast nuclear, slow CCS case

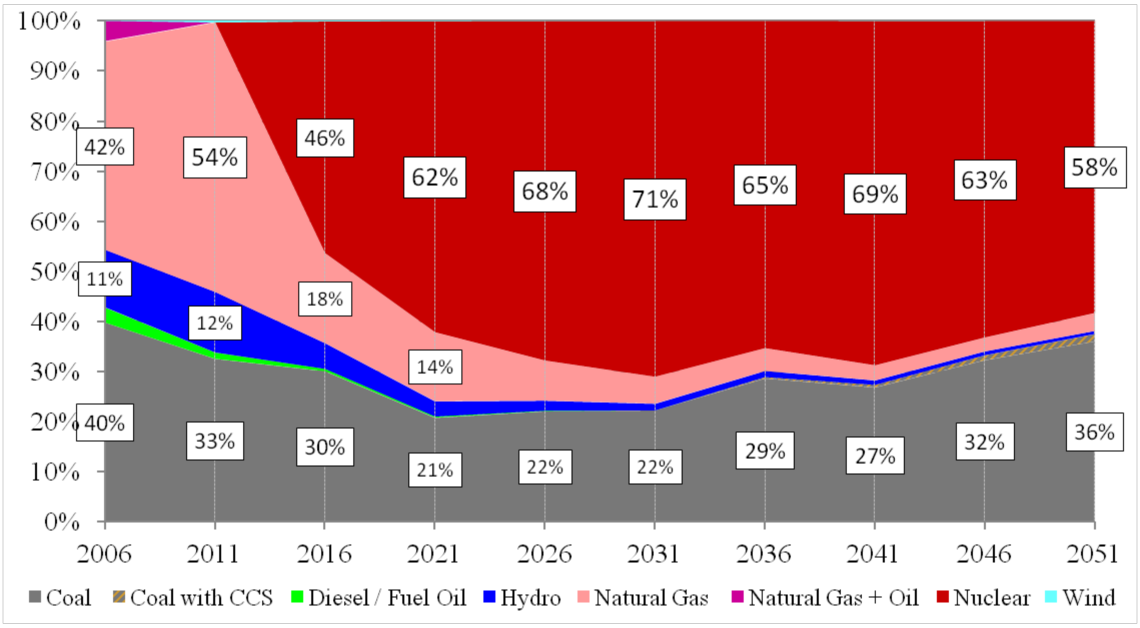

Figure 5.15. Breakdown of the primary energy resource consumed in electricity generation in the 10 per cent reduction, fast nuclear, slow CCS case

5.3.1.3. The 10 Per Cent Reduction, Slow Nuclear, Fast CCS Scenario.

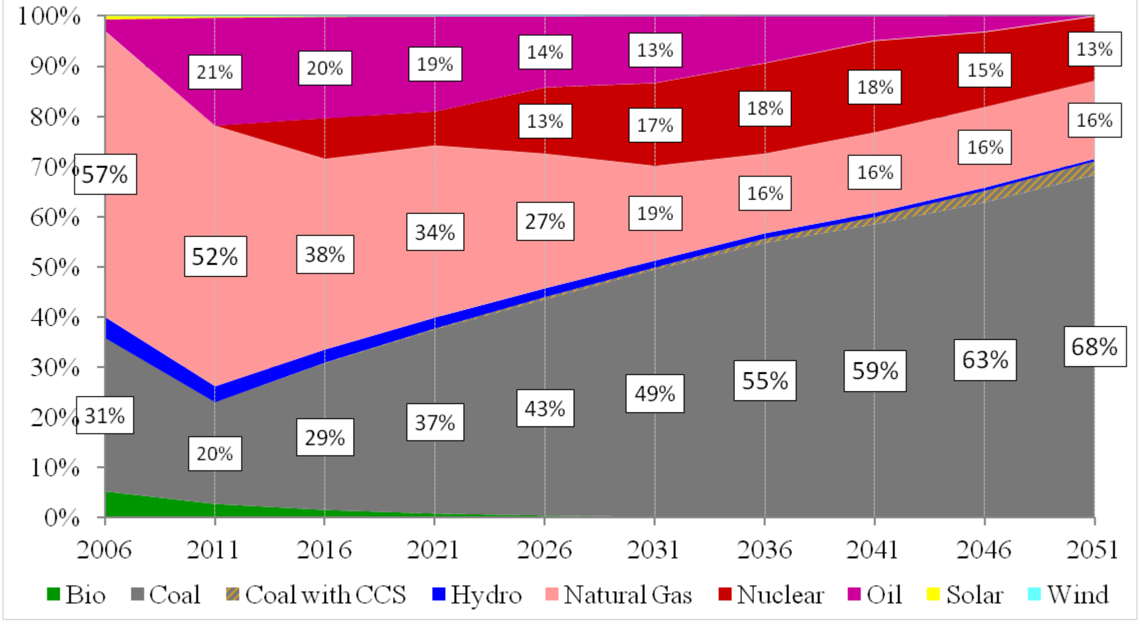

Figure 5.16. Breakdown of the primary energy resource consumption in the 10 per cent reduction, slow nuclear, fast CCS case

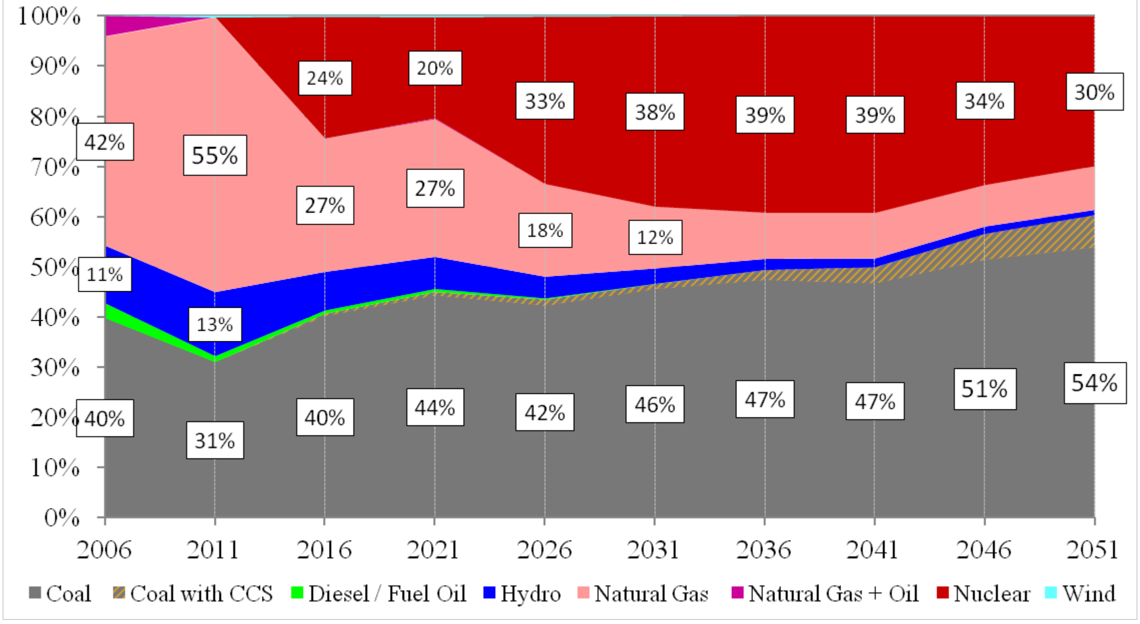

Figure 5.17. Breakdown of the primary energy resource consumed in electricity generation in the 10 per cent reduction, slow nuclear, fast CCS case

5.3.1.4. The 10 Per Cent Reduction, Slow Nuclear, Slow CCS Scenario.

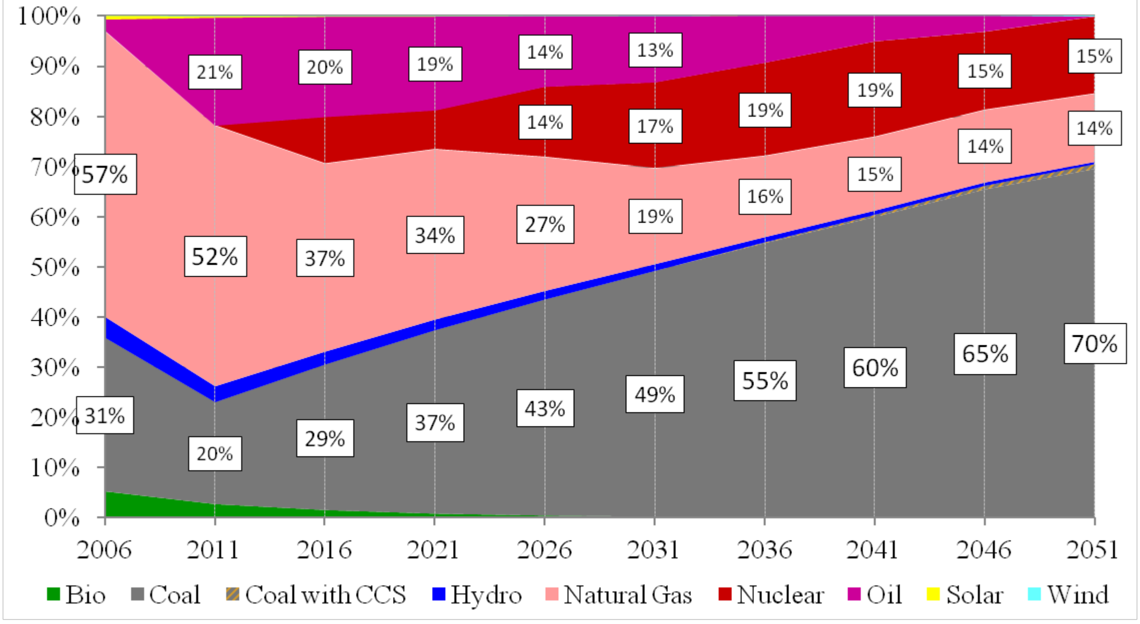

Figure 5.18. Breakdown of the primary energy resource consumption in the 10 per cent reduction, slow nuclear, slow CCS case

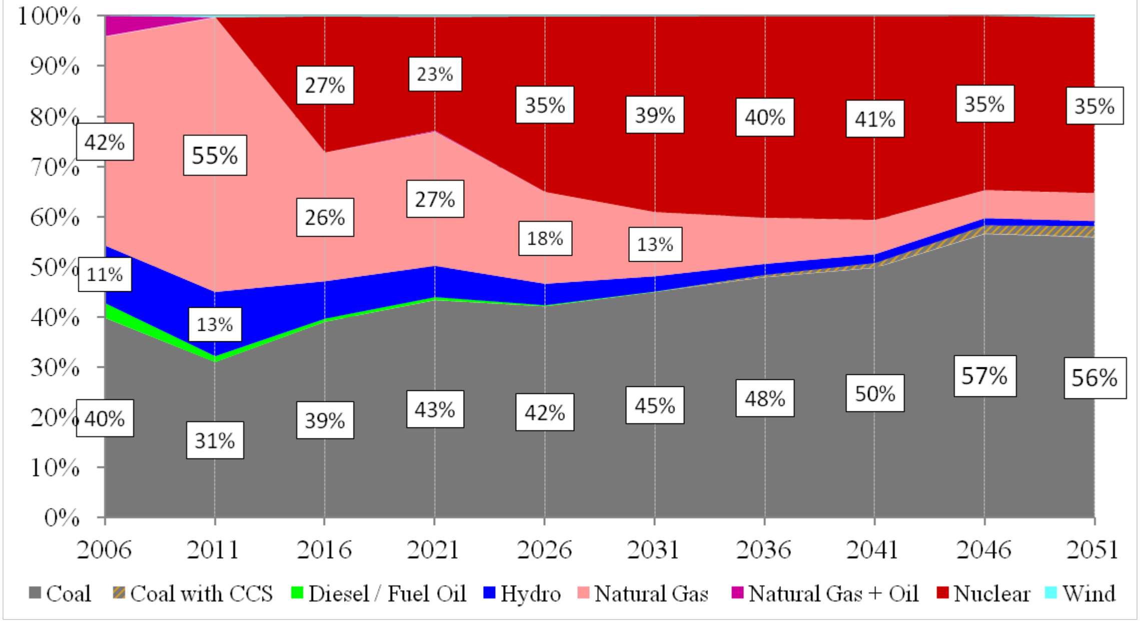

Figure 5.19. Breakdown of the primary energy resource consumed in electricity generation in the 10 per cent reduction, slow nuclear, slow CCS case

5.3.2. The 20 Per Cent Reduction Scenarios

The “fast nuclear, fast CCS” scenario employs nuclear power from the year 2026 onwards, dominantly —as portrayed in Figures 5.3.2.1 and 5.3.2.1. In the year 2011, natural gas and hydro-electric power is consumed to generate the required electricity (nuclear investments are not allowed until 2016). The coal consumption does not exceed one-fourth of total energy consumption. In the period 2011–2026, the natural gas consumption declines rapidly, as nuclear investments are made.

The energy breakdown regarding the “fast nuclear, slow CCS” scenario (shown in Figures 5.3.2.2 and 5.3.2.2) is very similar to the “fast nuclear, fast CCS” scenario. Since the coal consumption is at a low level, the decrease in the installment rate of CCS technology does not cause a significant change in the energy breakdown. Beginning from 2016, the nuclear energy consumption dominates the electricity generation, having a share of 76 per cent in 2016 and reaching 89 per cent of the electricity generation by 2051.

In both of the “slow nuclear” scenarios, the nuclear energy consumption does not exceed one-fourth of the total primary energy consumption, as shown in Figures 5.3.2.3, 5.3.2.3, 5.3.2.4 and 5.3.2.4. The share of coal consumption increases linearly through the period 2011–2051, reaching 56 per cent by 2051. The natural gas consumption maintains its primary energy consumption share of 22 per cent through the period 2031–2051. In 2011, before the availability of nuclear investments, 69 per cent of the electricity is generated through natural gas consumption.

5.3.2.1. The 20 Per Cent Reduction, Fast Nuclear, Fast CCS Scenario.

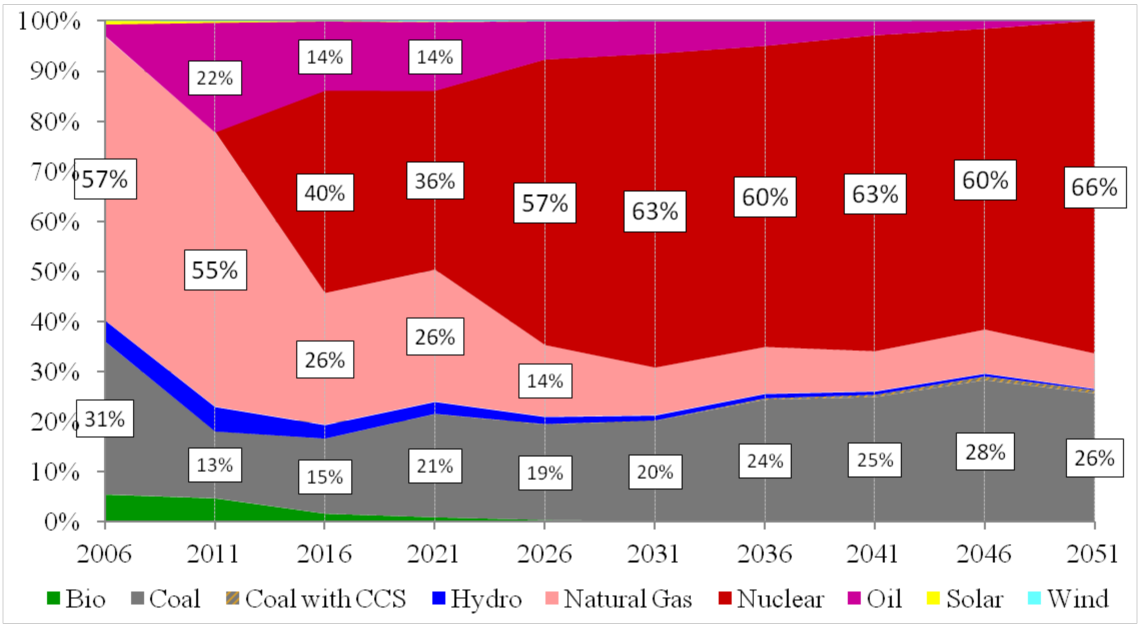

Figure 5.20. Breakdown of the primary energy resource consumption in the 20 per cent reduction, fast nuclear, fast CCS case

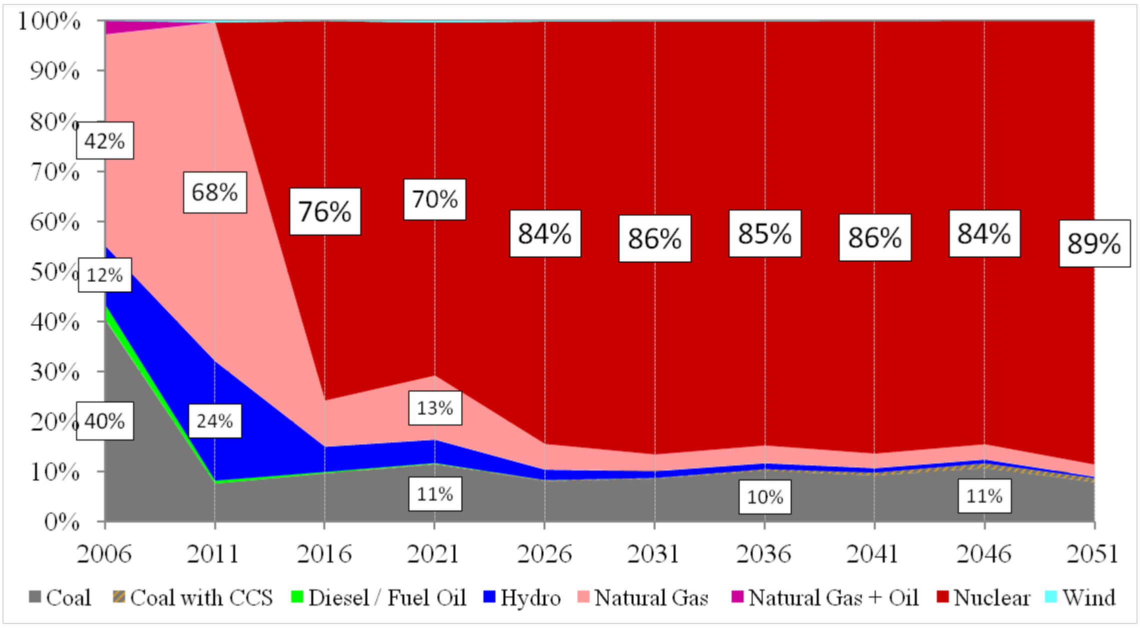

Figure 5.21. Breakdown of the primary energy resource consumed in electricity generation in the 20 per cent reduction, fast nuclear, fast CCS case

5.3.2.2. The 20 Per Cent Reduction, Fast Nuclear, Slow CCS Scenario.

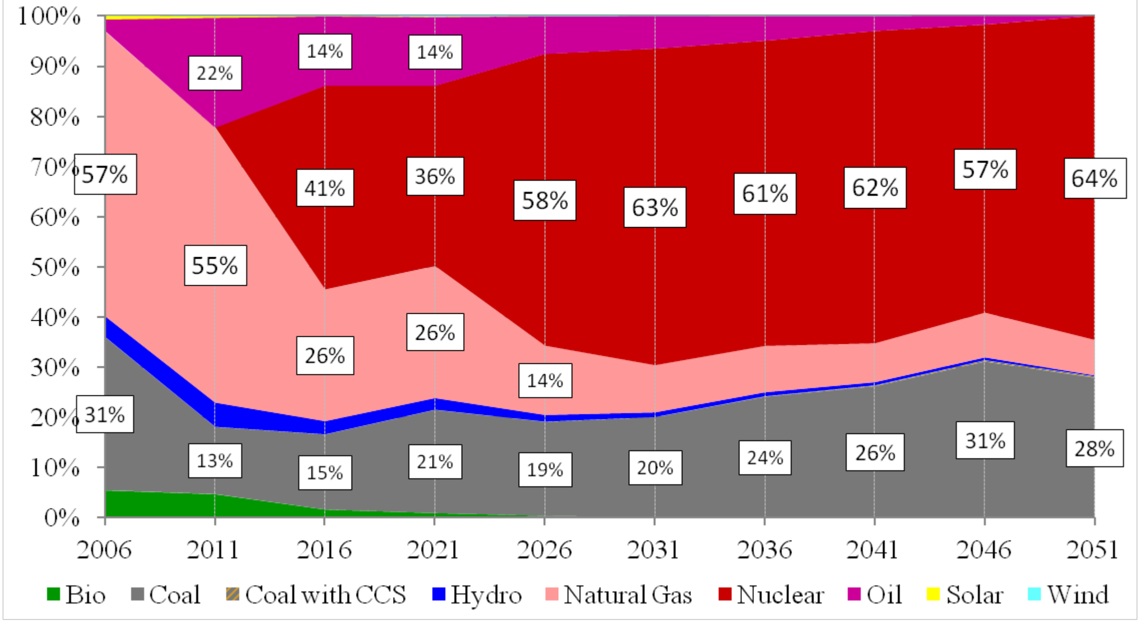

Figure 5.22. Breakdown of the primary energy resource consumption in the 20 per cent reduction, fast nuclear, slow CCS case

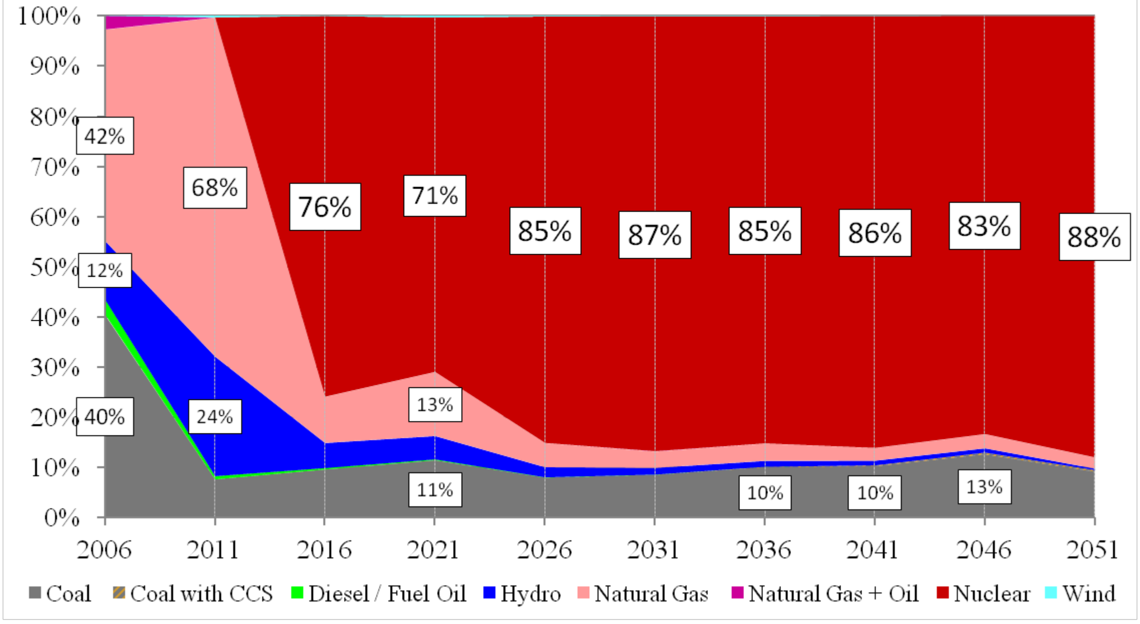

Figure 5.23. Breakdown of the primary energy resource consumed in electricity generation in the 20 per cent reduction, fast nuclear, slow CCS case

5.3.2.3. The 20 Per Cent Reduction, Slow Nuclear, Fast CCS Scenario.

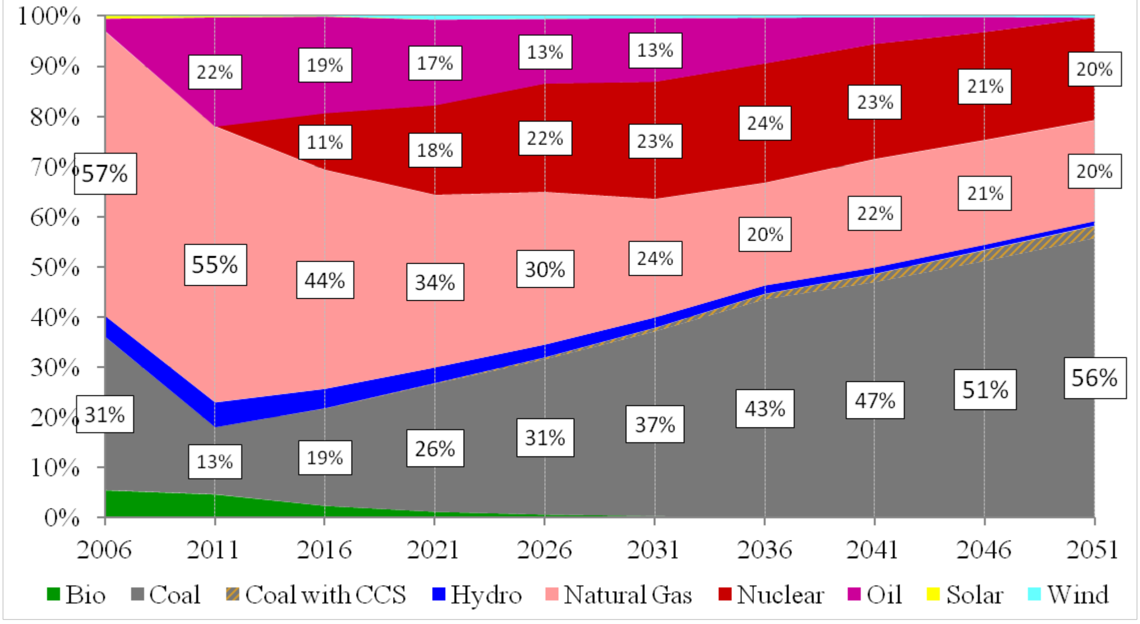

Figure 5.24. Breakdown of the primary energy resource consumption in the 20 per cent reduction, slow nuclear, fast CCS case

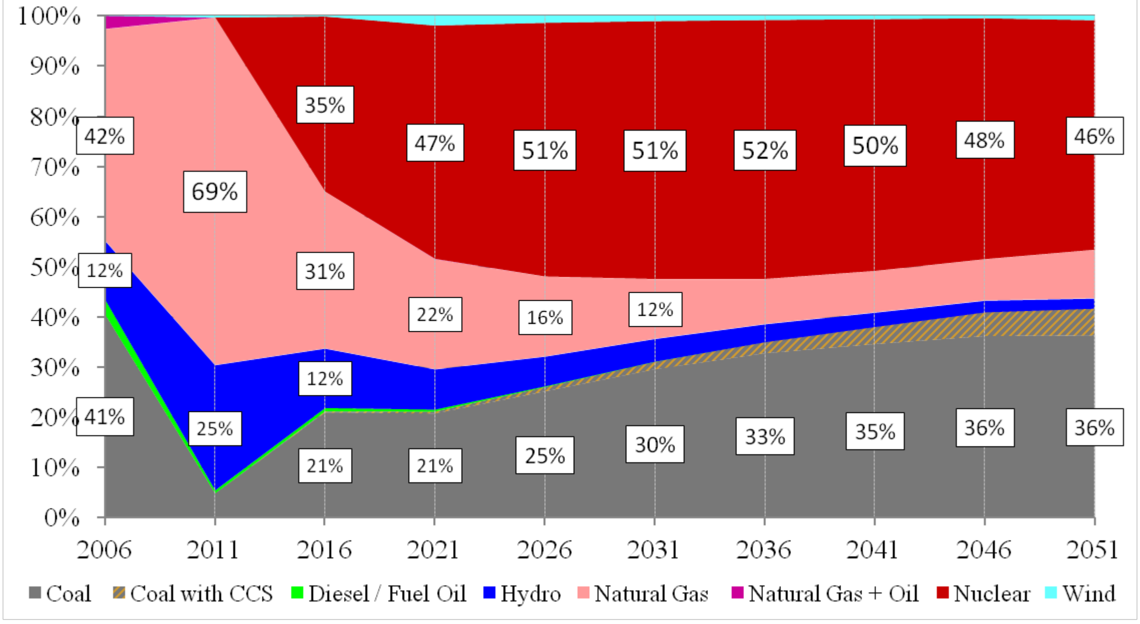

Figure 5.25. Breakdown of the primary energy resource consumed in electricity generation in the 20 per cent reduction, slow nuclear, fast CCS case

5.3.2.4. The 20 Per Cent Reduction, Slow Nuclear, Slow CCS Scenario.

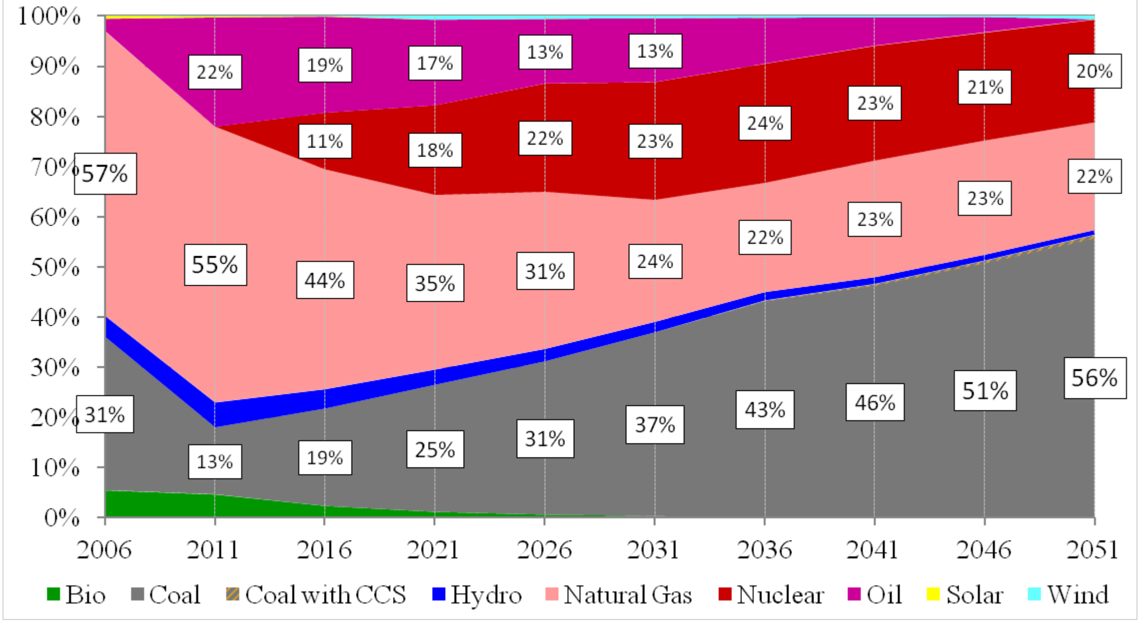

Figure 5.26. Breakdown of the primary energy resource consumption in the 20 per cent reduction, slow nuclear, slow CCS case

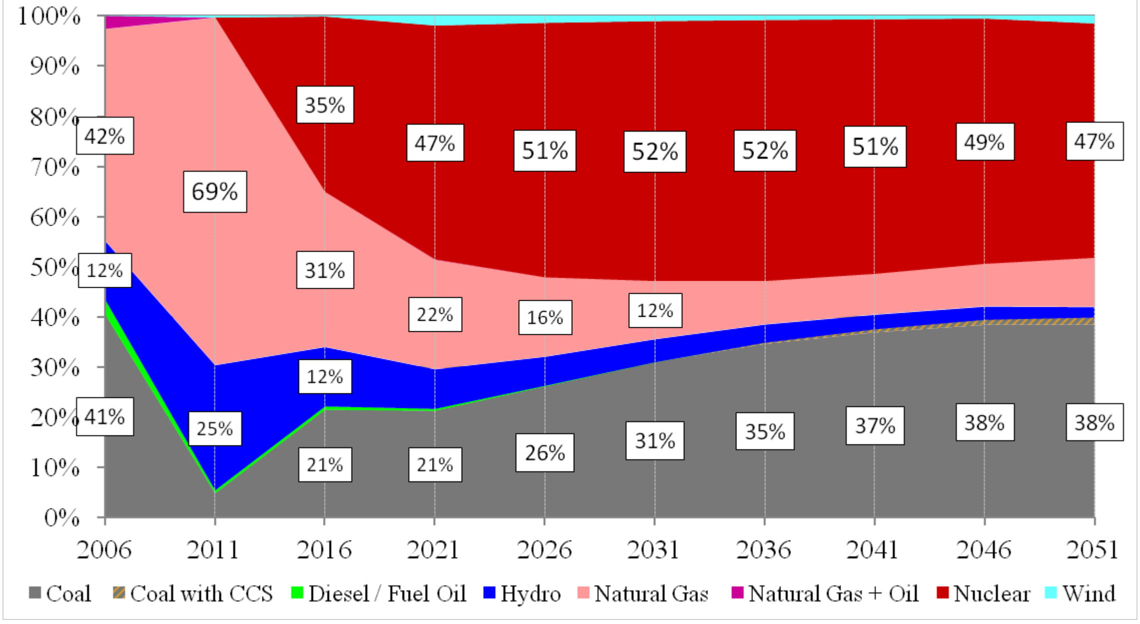

Figure 5.27. Breakdown of the primary energy resource consumed in electricity generation in the 20 per cent reduction, slow nuclear, slow CCS case

5.3.3. The 30 Per Cent Reduction Scenarios

The “fast nuclear, fast CCS” scenario mainly utilizes nuclear power from the year 2026 onwards (Figures 5.3.3.1 and 5.3.3.1). After 2011, the share of coal consumption in primary energy consumption is kept below 15 per cent. In the year 2011, natural gas and hydro-electric power are consumed to generate 98 per cent of the electricity (nuclear investments are not allowed until 2016). In the period 2016–2051, over 90 per cent of the electricity generation is due to the use of nuclear power.

The energy breakdowns regarding the “fast nuclear, slow CCS” scenario (shown in Figures 5.3.3.2 and 5.3.3.2) are very similar to the “fast nuclear, fast CCS” scenario, since the coal consumption is low (less than one-sixth of consumed primary energy and less than five per cent of energy used in electricity generation).

In the “slow nuclear” scenarios, the nuclear energy consumption does not exceed one-fourth of the total primary energy consumption, as shown in Figures 5.3.3.3, 5.3.3.3, 5.3.3.4 and 5.3.3.4. Although the share of coal consumption increases linearly through the period 2011–2051, the increase is less than the corresponding 20 per cent reduction scenarios, reaching 51 per cent by 2051. The natural gas consumption maintains its primary energy consumption share of 25 per cent through the period 2031–2051. In 2011, before the availability of nuclear investments, 69 per cent of the electricity is generated through natural gas consumption. Also, from 2021 onwards, wind power is employed in the generation of electricity, having a share of five per cent in electricity generation.

5.3.3.1. The 30 Per Cent Reduction, Fast Nuclear, Fast CCS Scenario.

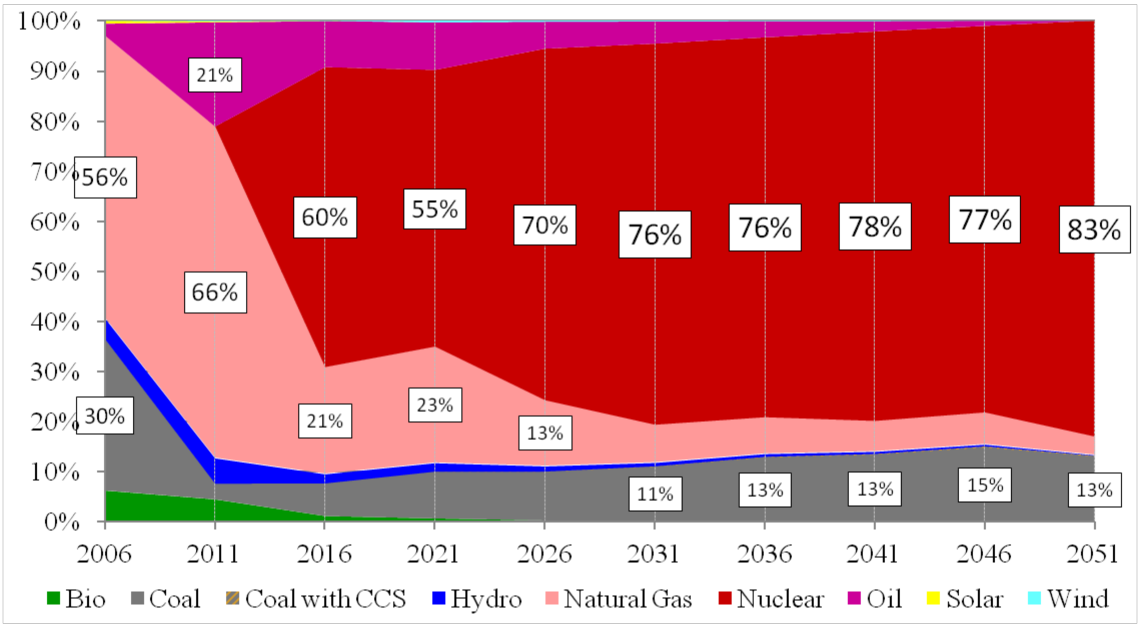

Figure 5.28. Breakdown of the primary energy resource consumption in the 30 per cent reduction, fast nuclear, fast CCS case

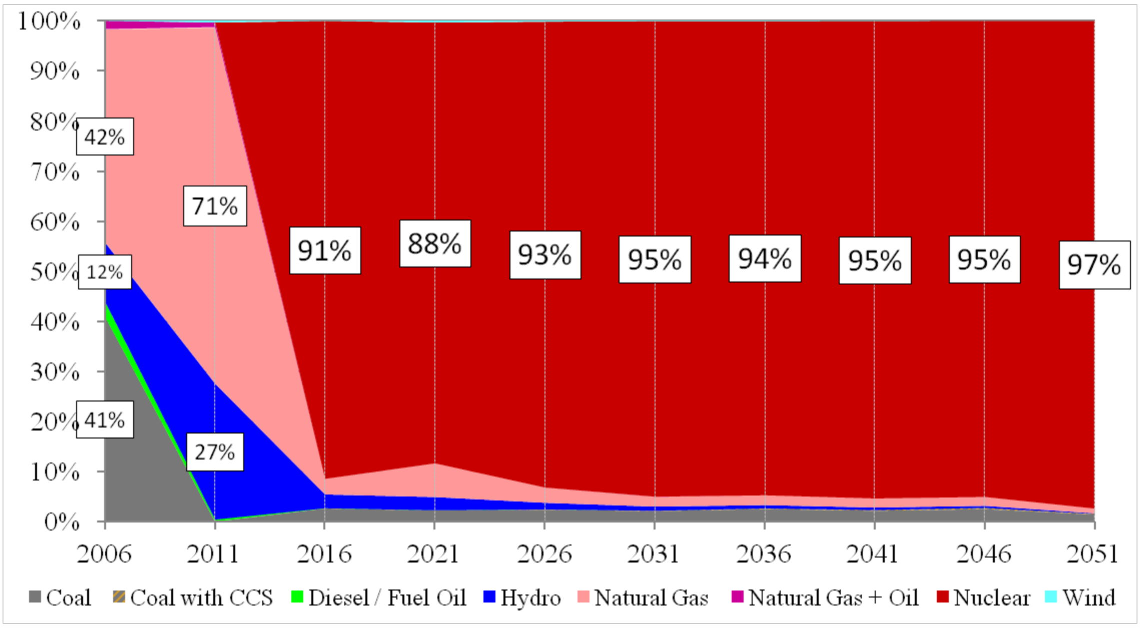

Figure 5.29. Breakdown of the primary energy resource consumed in electricity generation in the 30 per cent reduction, fast nuclear, fast CCS case

5.3.3.2. The 30 Per Cent Reduction, Fast Nuclear, Slow CCS Scenario.

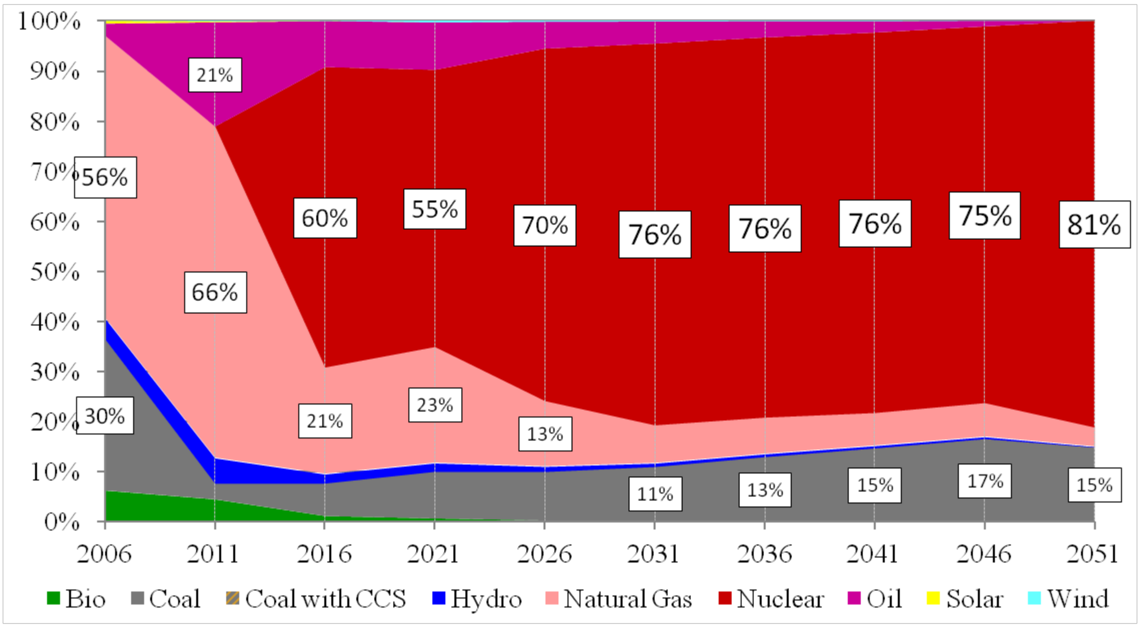

Figure 5.30. Breakdown of the primary energy resource consumption in the 30 per cent reduction, fast nuclear, slow CCS case

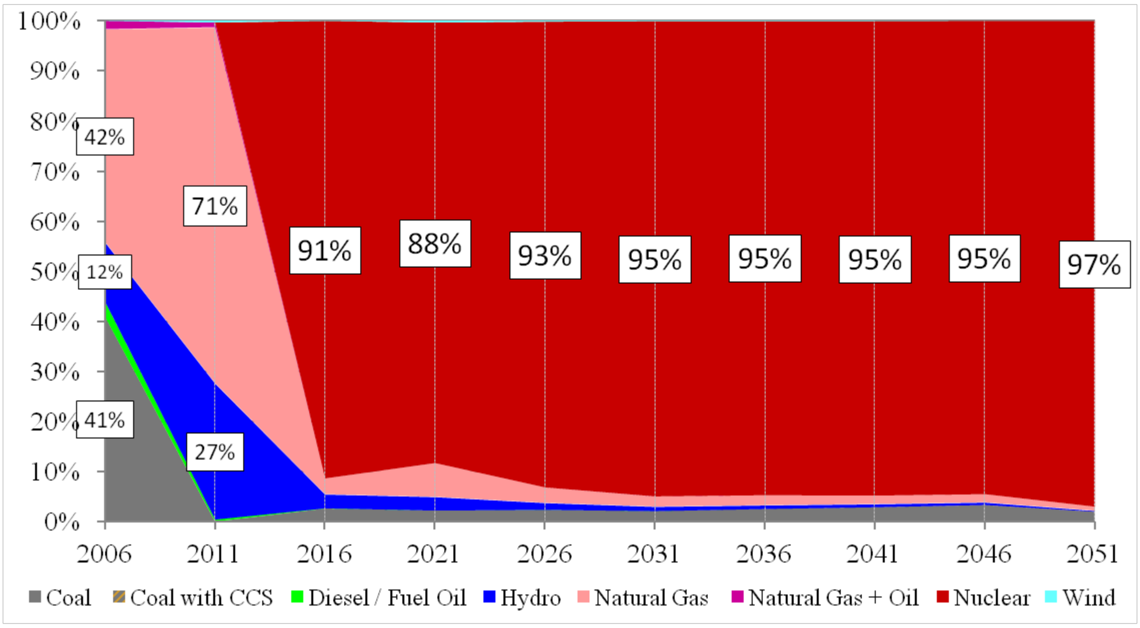

Figure 5.31. Breakdown of the primary energy resource consumed in electricity generation in the 30 per cent reduction, fast nuclear, slow CCS case

5.3.3.3. The 30 Per Cent Reduction, Slow Nuclear, Fast CCS Scenario.

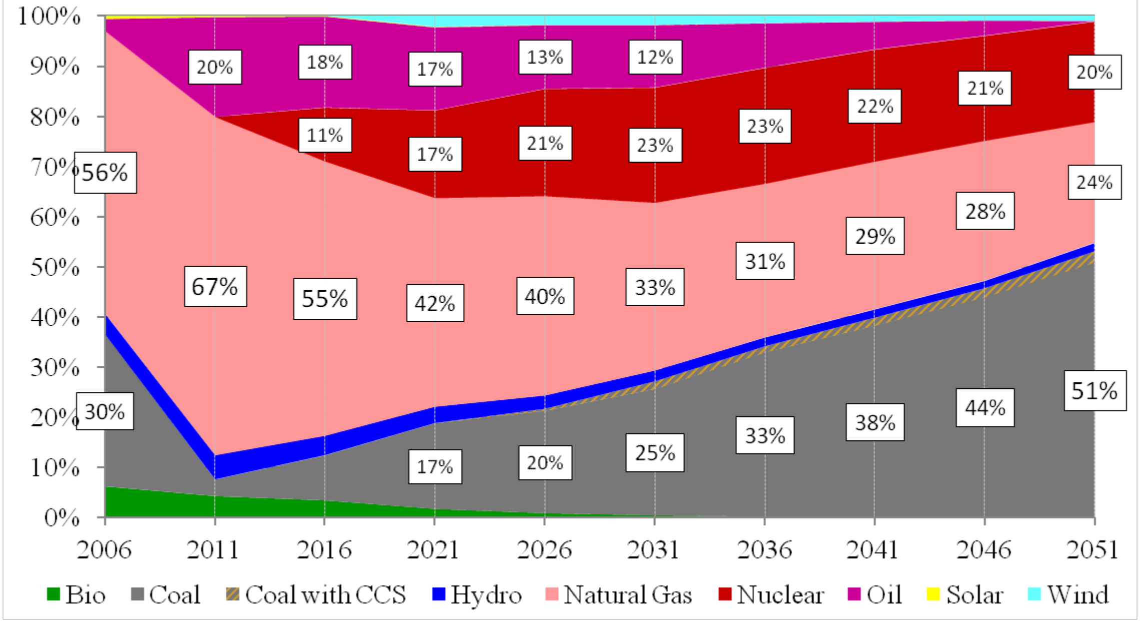

Figure 5.32. Breakdown of the primary energy resource consumption in the 30 per cent reduction, slow nuclear, fast CCS case

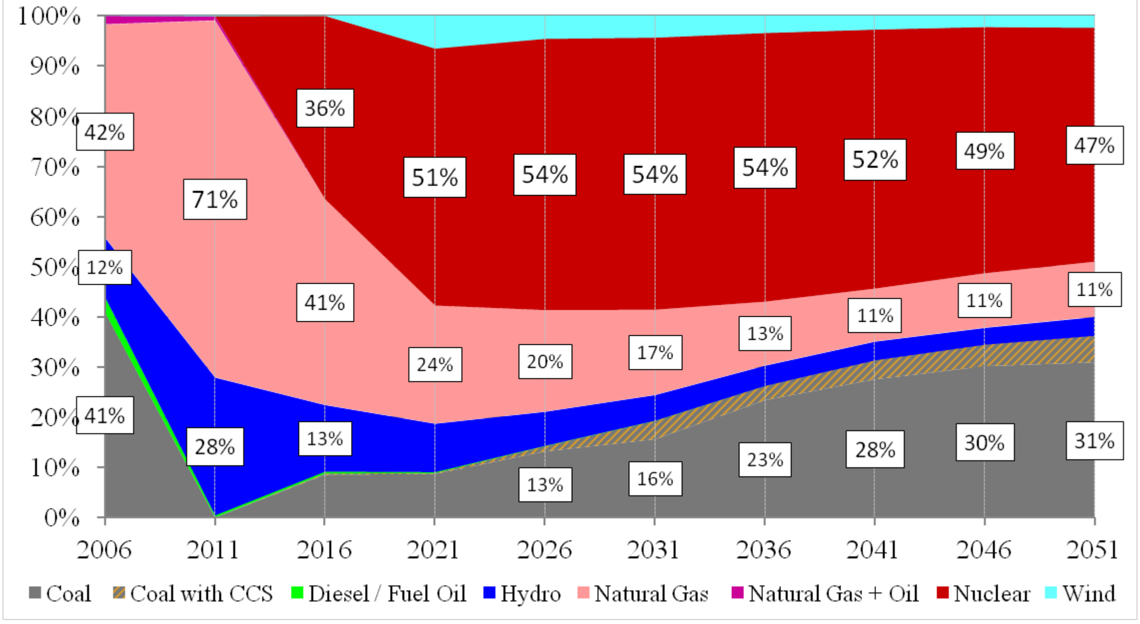

Figure 5.33. Breakdown of the primary energy resource consumed in electricity generation in the 30 per cent reduction, slow nuclear, fast CCS case

5.3.3.4. The 30 Per Cent Reduction, Slow Nuclear, Slow CCS Scenario.

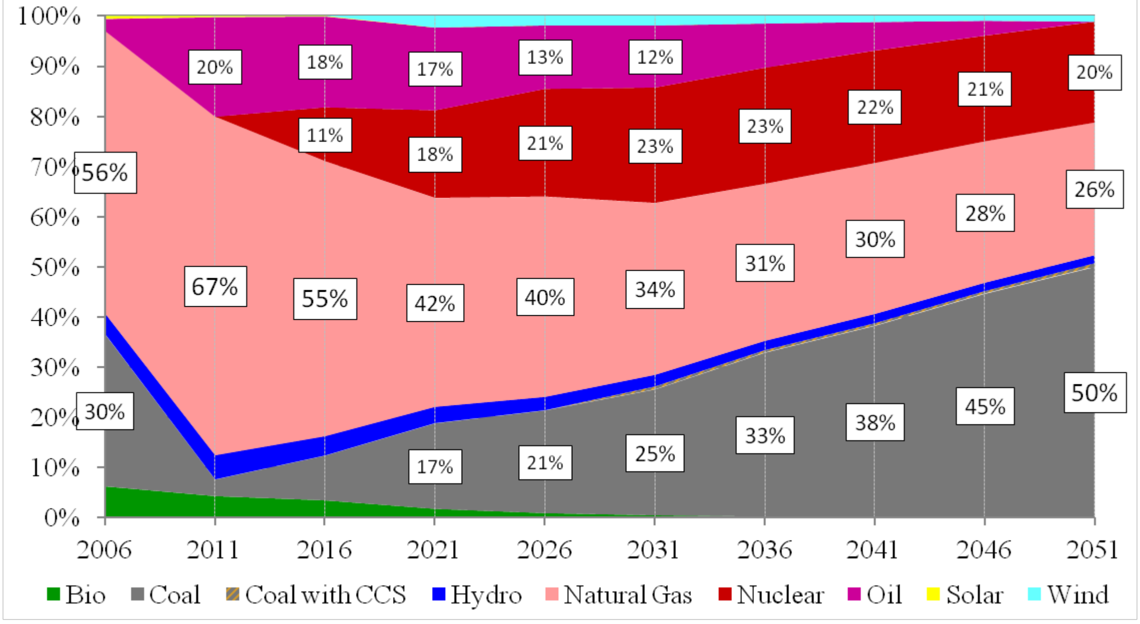

Figure 5.34. Breakdown of the primary energy resource consumption in the 30 per cent reduction, slow nuclear, slow CCS case

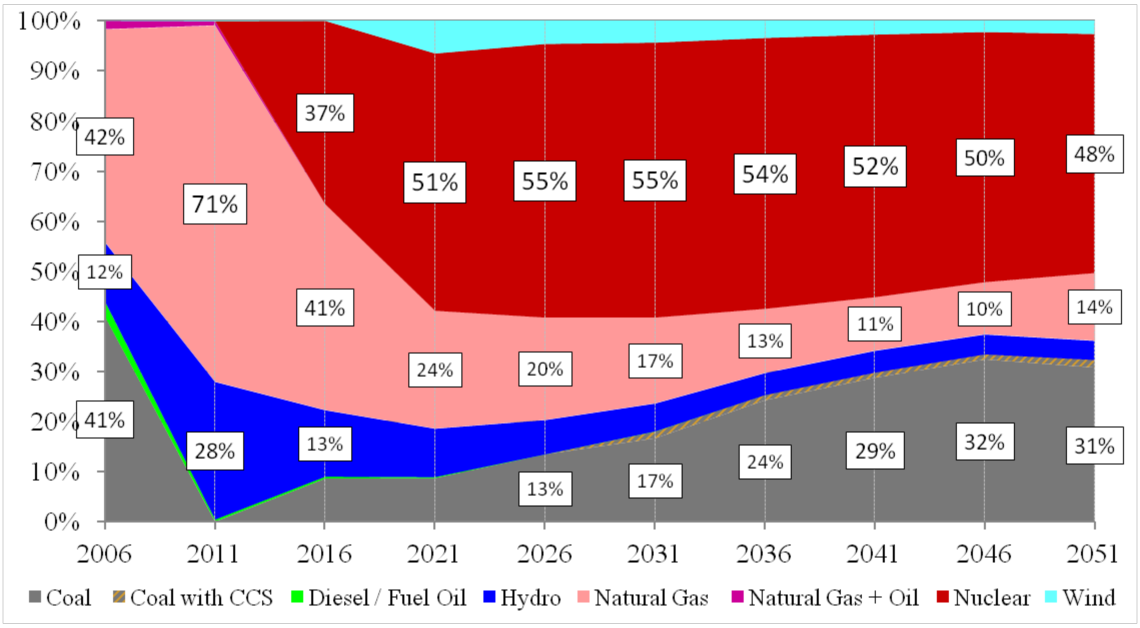

Figure 5.35. Breakdown of the primary energy resource consumed in electricity generation in the 30 per cent reduction, slow nuclear, slow CCS case

5.3.4. The 40 Per Cent Reduction Scenarios

Both in the breakdown of the primary energy consumption and the breakdown of energy used in electricity generation, the “fast nuclear, fast CCS” and “fast nuclear, slow CCS” scenarios are very similar (Figures 5.3.4.1, 5.3.4.1, 5.3.4.2 and 5.3.4.2), since the coal consumption does not exceed 10 per cent of the primary energy consumption after 2006 and the levels of CCS installment do not have any effect on the energy breakdown figures. After 2011, the share of natural gas consumption in primary energy consumption falls rapidly and gives way to the consumption of nuclear energy. In the year 2011, natural gas and hydro and bio energy are consumed to generate all of the electricity (nuclear investments are not allowed until 2016). From 2026 onwards, about all of the electricity generation is due to the use of nuclear power.

In the “slow nuclear” scenarios, the nuclear energy consumption does not exceed one-fourth of the total primary energy consumption, as shown in Figures 5.3.4.3, 5.3.4.3, 5.3.4.4 and 5.3.4.4. The share of coal consumption increases linearly through the period 2011–2051, reaching 51 per cent by 2051. In both of these “slow nuclear” scenarios, a significant portion of this share utilizes CCS technology, the share of CCS installed coal consumption reaches 16 per cent of primary energy resource consumption and 34 per cent of energy used in electricity generation, by 2051. The natural gas consumption declines steadily, its primary energy consumption share decreases from 46 per cent in 2021 to 22 per cent in 2051. In 2011, before the availability of nuclear investments, 67 per cent of the electricity is generated through natural gas consumption, while 29 per cent is generated through hydro energy. Also, from 2021 onwards, wind power is employed in the generation of electricity, having a share of five per cent in electricity generation.

5.3.4.1. The 40 Per Cent Reduction, Fast Nuclear, Fast CCS Scenario.

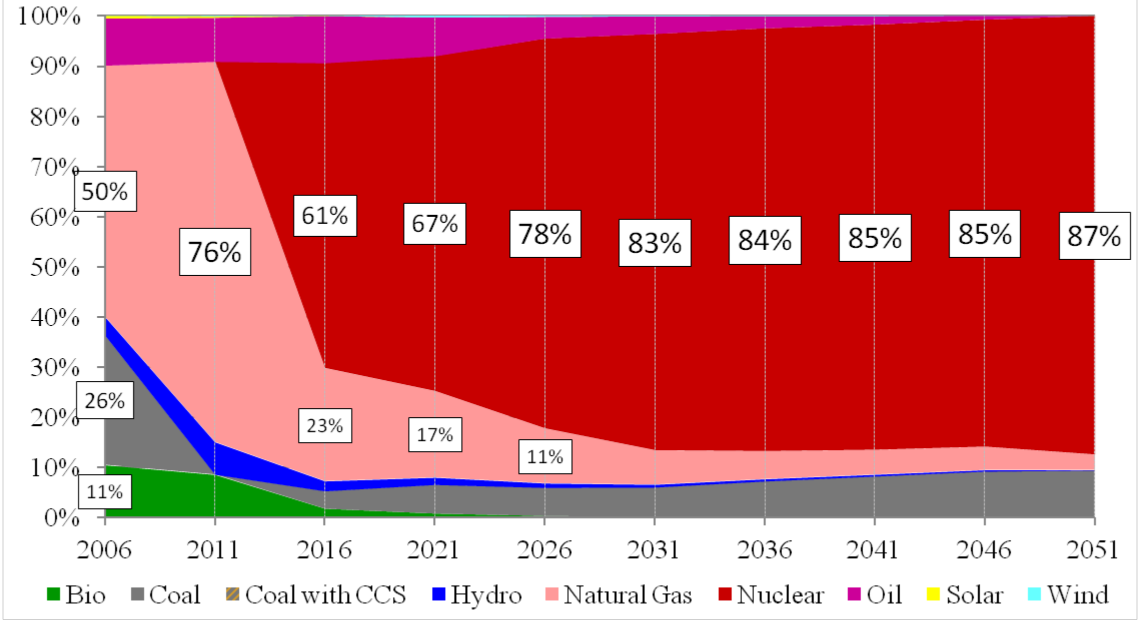

Figure 5.36. Breakdown of the primary energy resource consumption in the 40 per cent reduction, fast nuclear, fast CCS case

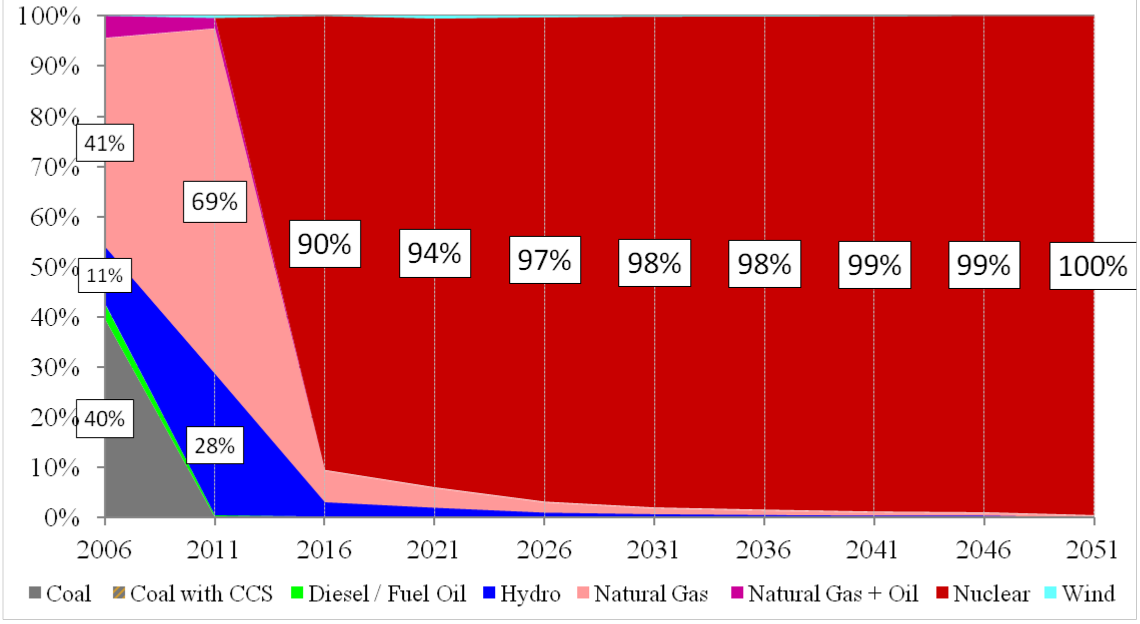

Figure 5.37. Breakdown of the primary energy resource consumed in electricity generation in the 40 per cent reduction, fast nuclear, fast CCS case

5.3.4.2. The 40 Per Cent Reduction, Fast Nuclear, Slow CCS Scenario.

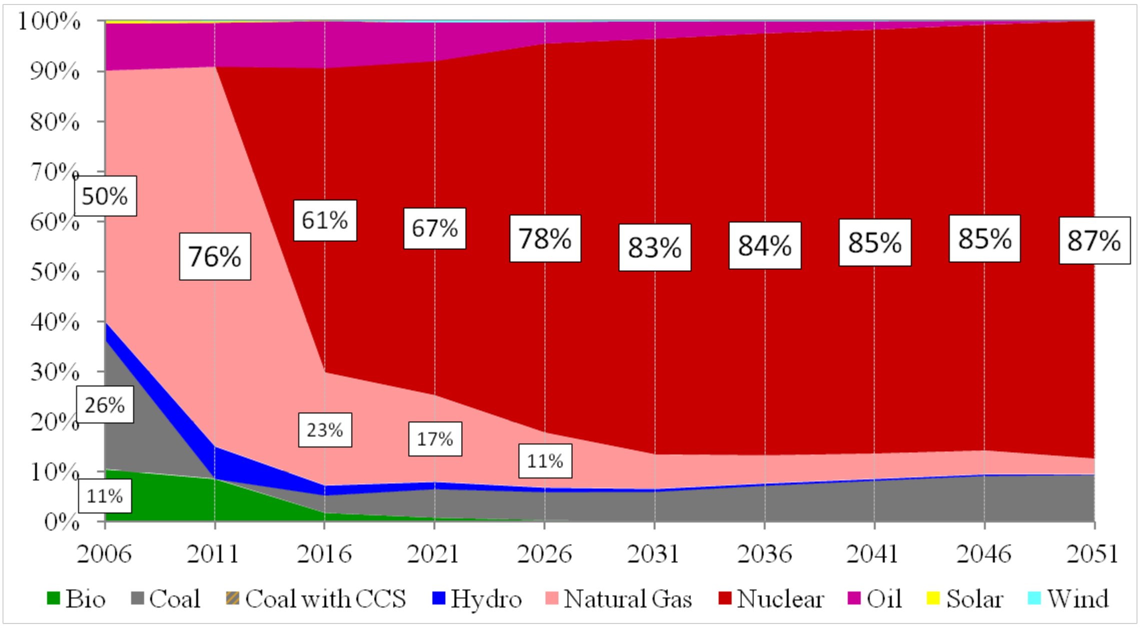

Figure 5.38. Breakdown of the primary energy resource consumption in the 40 per cent reduction, fast nuclear, slow CCS case

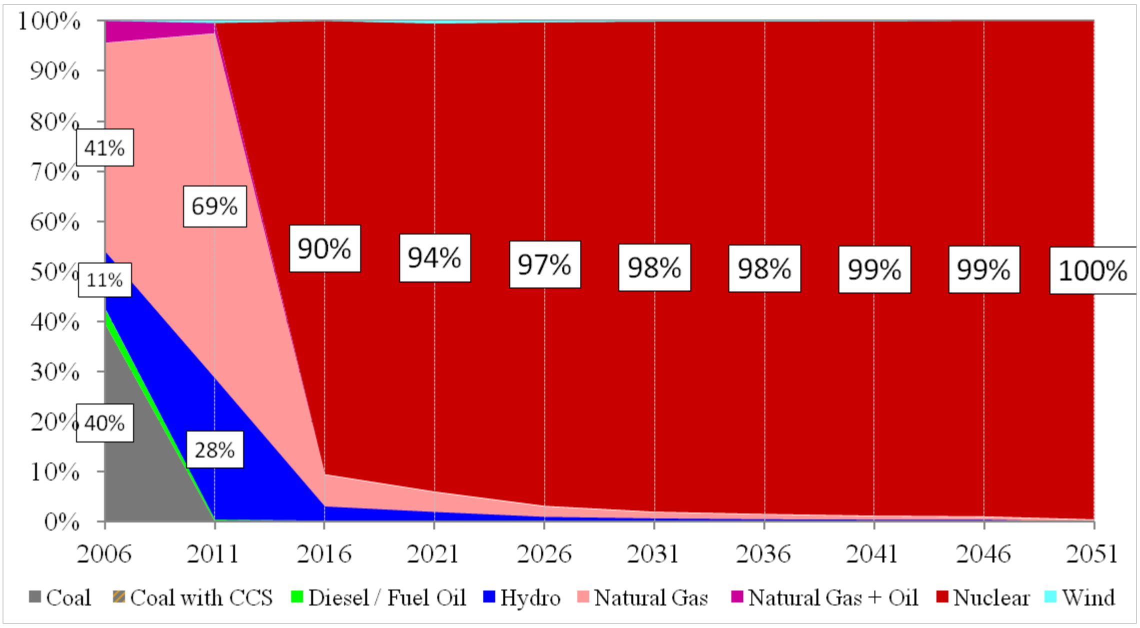

Figure 5.39. Breakdown of the primary energy resource consumed in electricity generation in the 40 per cent reduction, fast nuclear, slow CCS case

5.3.4.3. The 40 Per Cent Reduction, Slow Nuclear, Fast CCS Scenario.

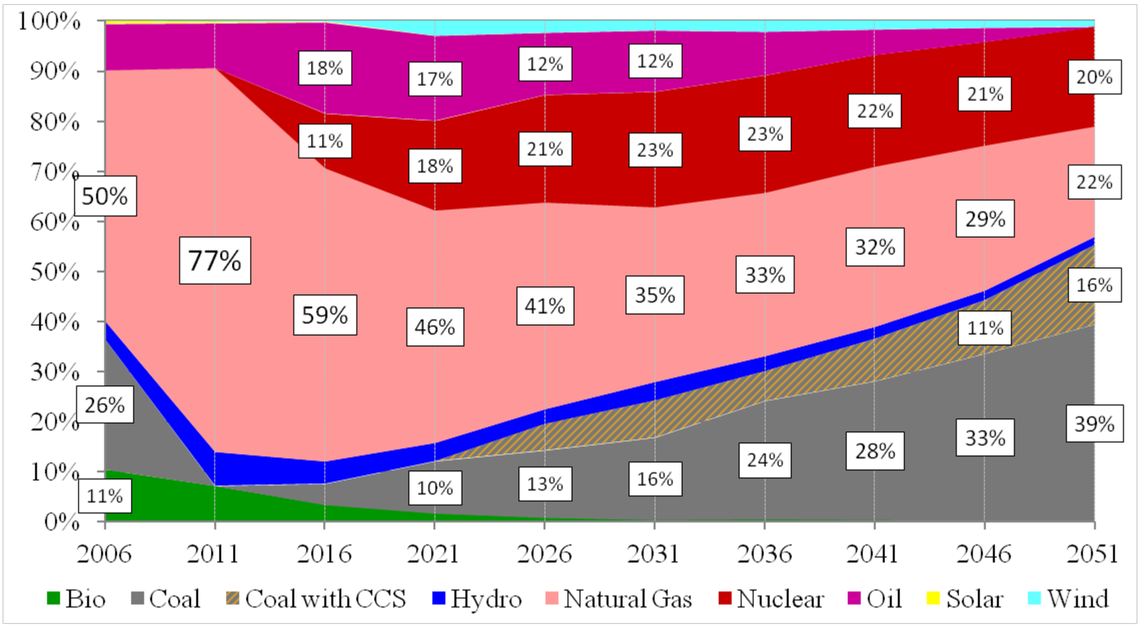

Figure 5.40. Breakdown of the primary energy resource consumption in the 40 per cent reduction, slow nuclear, fast CCS case

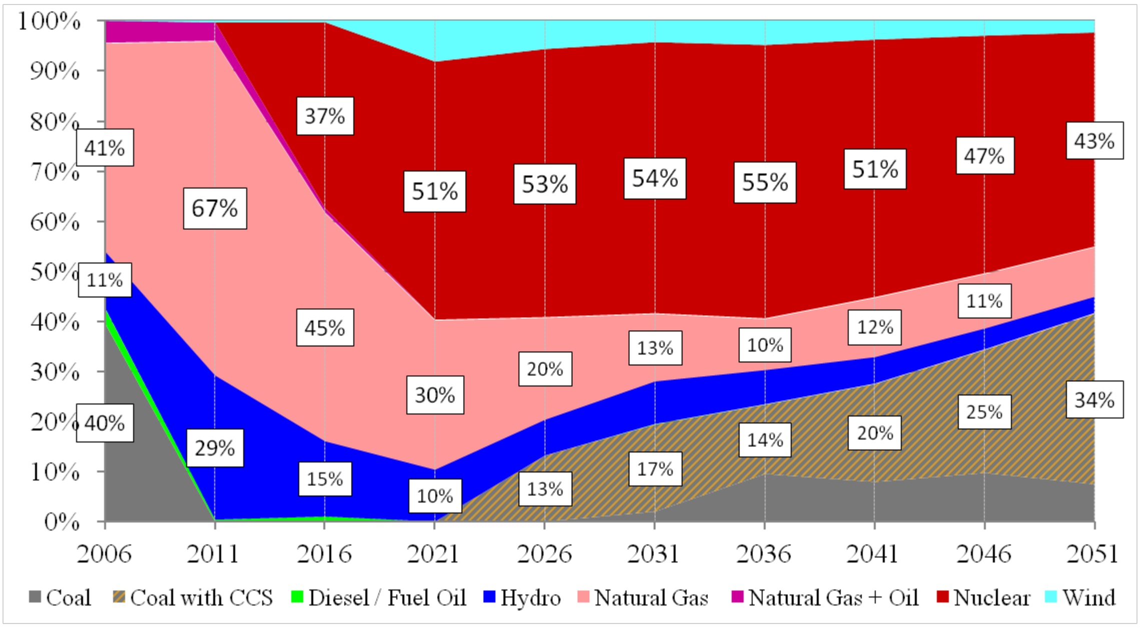

Figure 5.41. Breakdown of the primary energy resource consumed in electricity generation in the 40 per cent reduction, slow nuclear, fast CCS case

5.3.4.4. The 40 Per Cent Reduction, Slow Nuclear, Slow CCS Scenario.

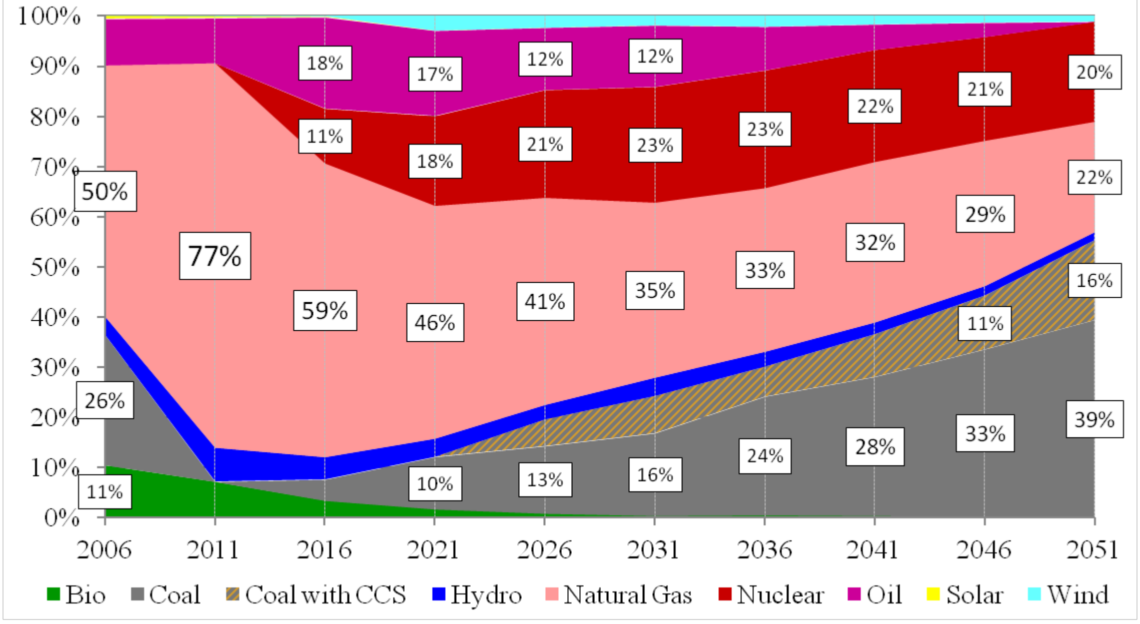

Figure 5.42. Breakdown of the primary energy resource consumption in the 40 per cent reduction, slow nuclear, slow CCS case

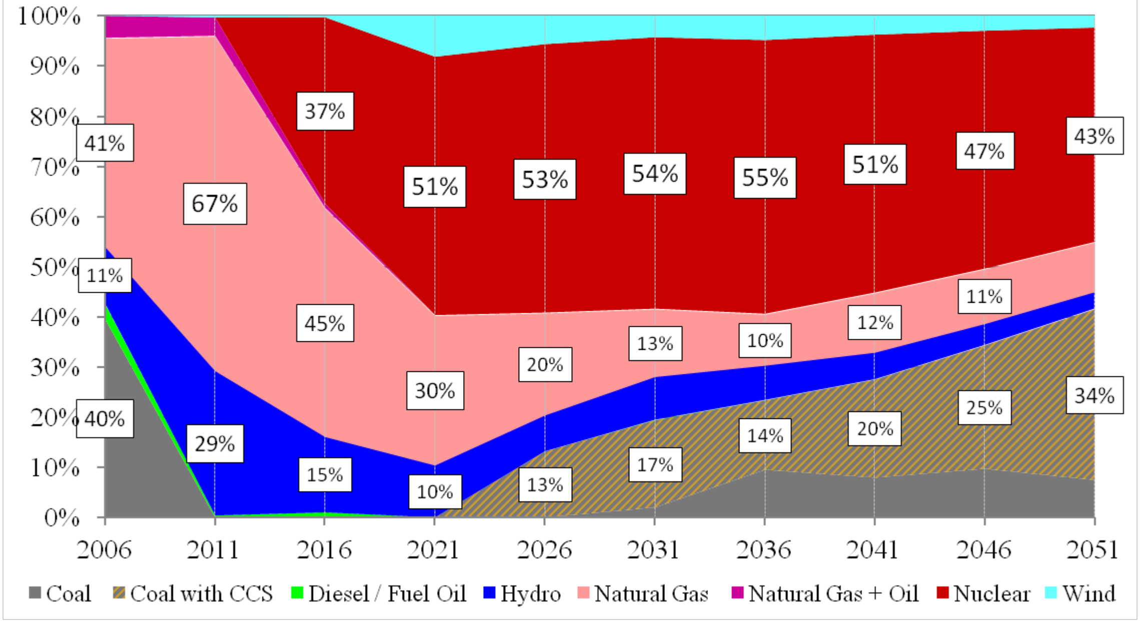

Figure 5.43. Breakdown of the primary energy resource consumed in electricity generation in the 40 per cent reduction, slow nuclear, slow CCS case

5.3.5. The 50 Per Cent Reduction Scenarios

Both in the breakdown of the primary energy consumption and the breakdown of energy used in electricity generation, the “fast nuclear, fast CCS” and “fast nuclear, slow CCS” scenarios are identical (Figures 5.3.5.1, 5.3.5.1, 5.3.5.2 and 5.3.5.2), since the coal consumption does not exceed seven per cent of the primary energy consumption after 2006 and the levels of CCS installment are trivial in determining the energy breakdown figures. After 2011, the share of natural gas consumption in primary energy consumption falls rapidly and yields to the consumption of nuclear energy. In the year 2011, natural gas and hydro-electric power is consumed to generate all of the electricity (nuclear investments are not allowed until 2016). From 2026 onwards, about all of the electricity generation is due to the use of nuclear power.

In the “slow nuclear” scenarios, the nuclear energy consumption does not exceed one-fourth of the total primary energy consumption, as shown in Figures 5.3.5.3, 5.3.5.3, 5.3.5.4 and 5.3.5.4. The share of coal consumption increases linearly through the period 2021–2051, reaching 54 per cent by 2051. In both of these “slow nuclear” scenarios, a significant portion of this share utilizes CCS technology, the share of CCS installed coal consumption reaches 23 per cent of primary energy resource consumption and 47 per cent of energy used in electricity generation, by 2051. All of the coal utilized in electricity generation employs the CCS technology. Along the time horizon, the natural gas consumption declines, from 77 per cent in 2011 to 23 per cent in 2051. In 2011, before the availability of nuclear investments, 50 per cent of the electricity is generated through natural gas consumption, while 15 per cent is generated through hydro energy and 34 per cent is generated through bio energy. Also, from 2021 onwards, wind power is employed in the generation of electricity, having a share of eight per cent in electricity generation.

5.3.5.1. The 50 Per Cent Reduction, Fast Nuclear, Fast CCS Scenario.

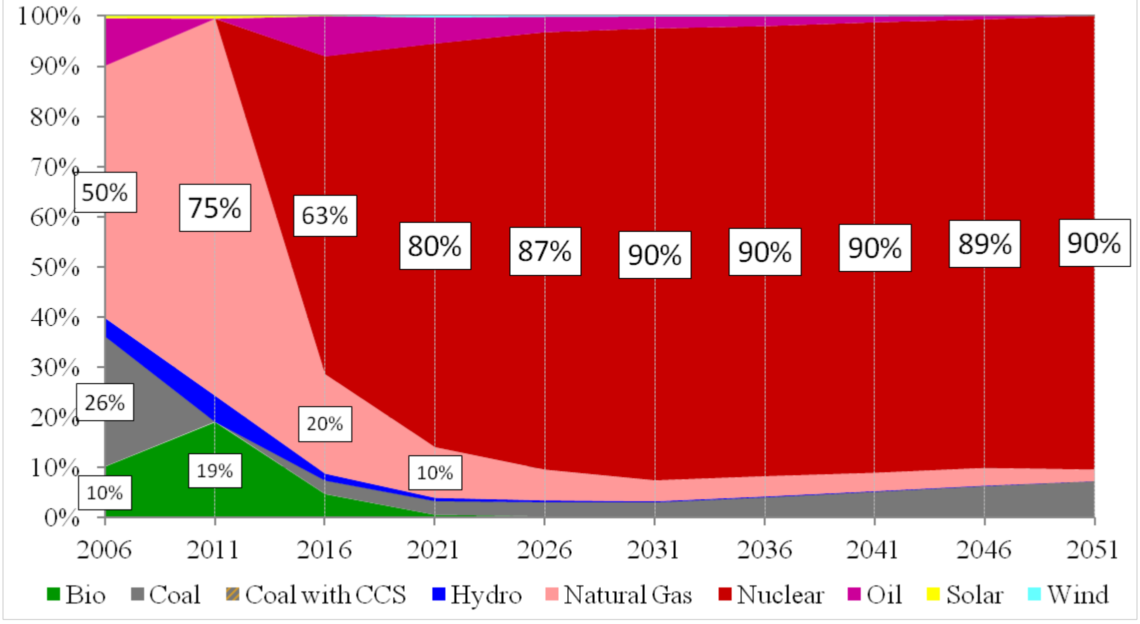

Figure 5.44. Breakdown of the primary energy resource consumption in the 50 per cent reduction, fast nuclear, fast CCS case

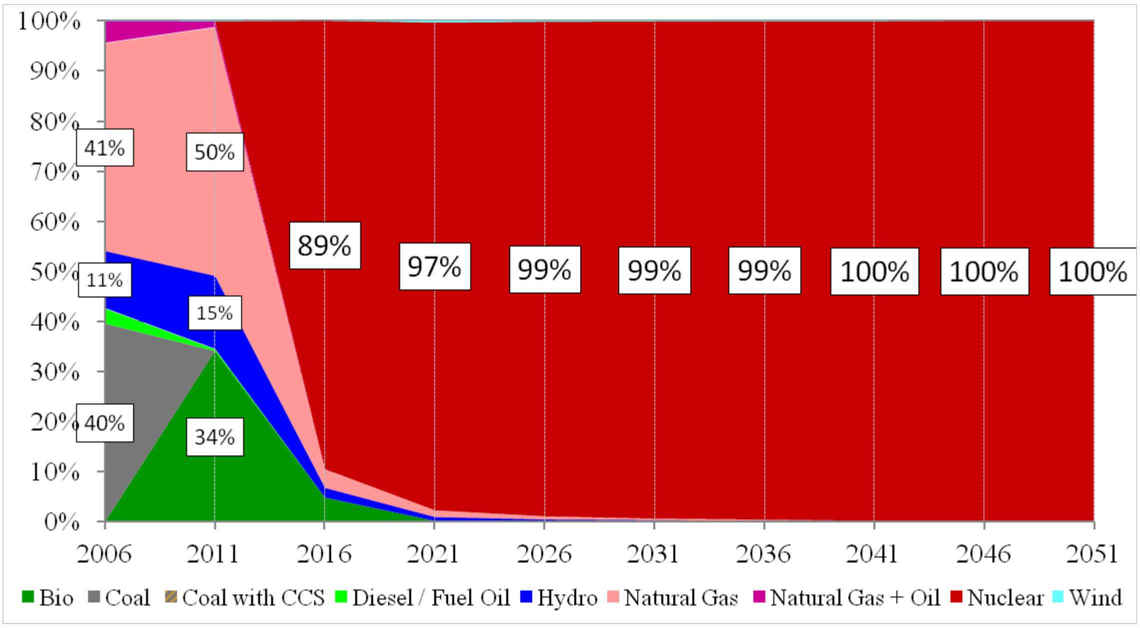

Figure 5.45. Breakdown of the primary energy resource consumed in electricity generation in the 50 per cent reduction, fast nuclear, fast CCS case

5.3.5.2. The 50 Per Cent Reduction, Fast Nuclear, Slow CCS Scenario.

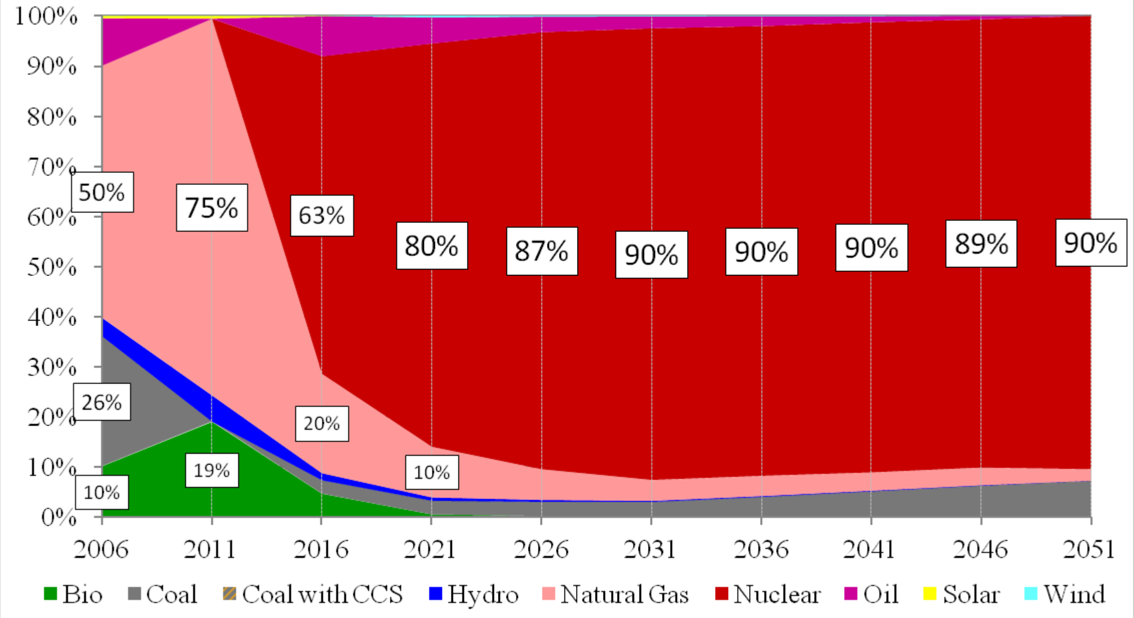

Figure 5.46. Breakdown of the primary energy resource consumption in the 50 per cent reduction, fast nuclear, slow CCS case

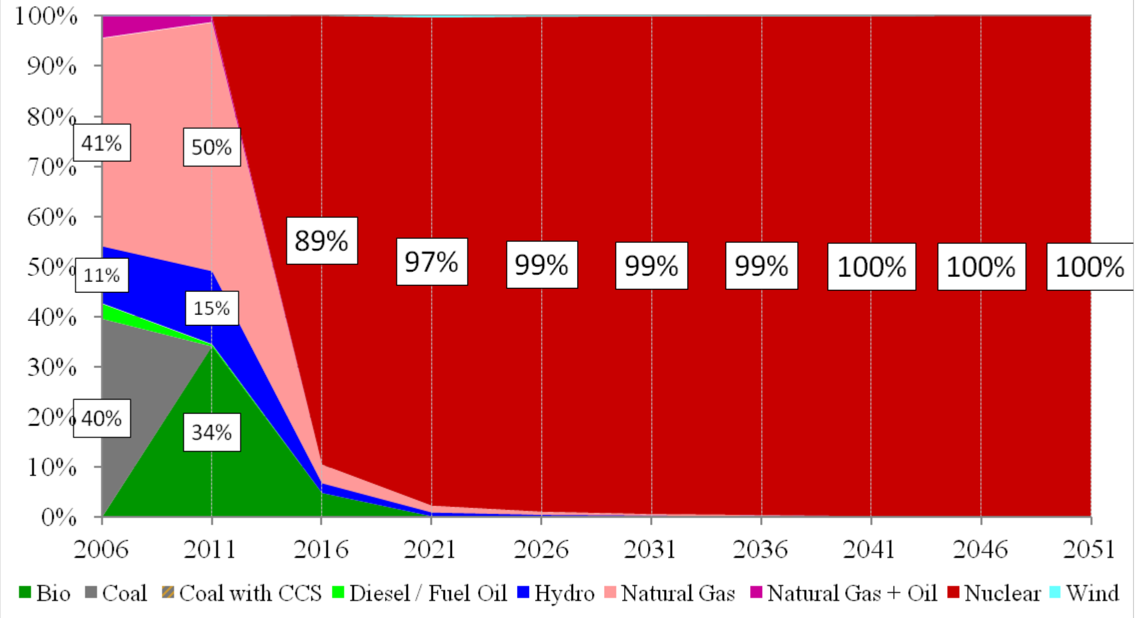

Figure 5.47. Breakdown of the primary energy resource consumed in electricity generation in the 50 per cent reduction, fast nuclear, slow CCS case

5.3.5.3. The 50 Per Cent Reduction, Slow Nuclear, Fast CCS Scenario.

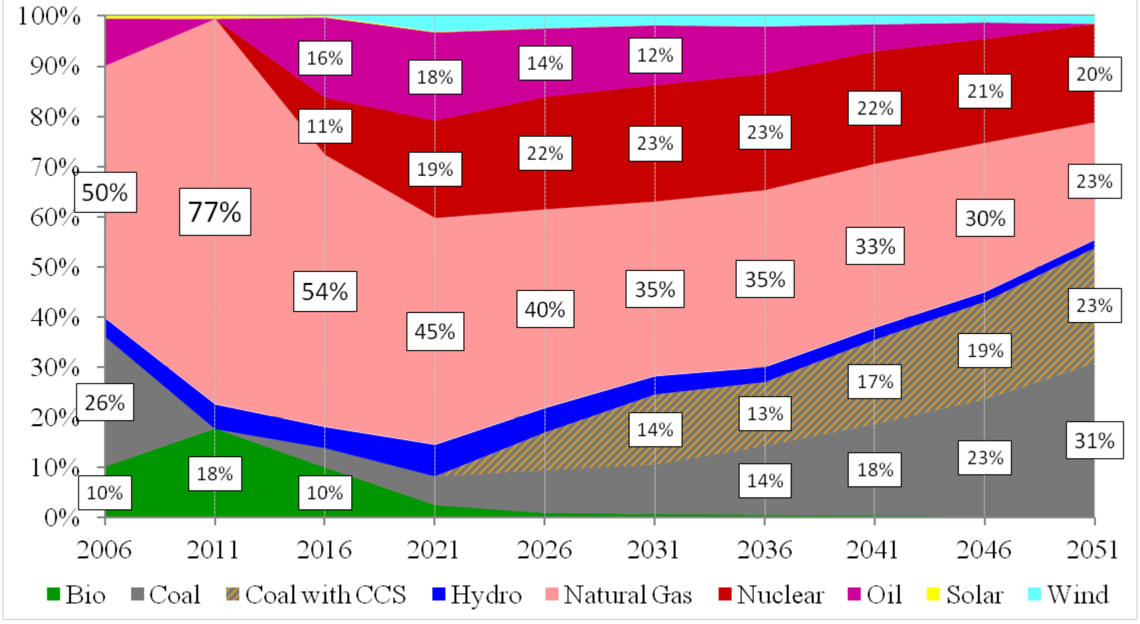

Figure 5.48. Breakdown of the primary energy resource consumption in the 50 per cent reduction, slow nuclear, fast CCS case

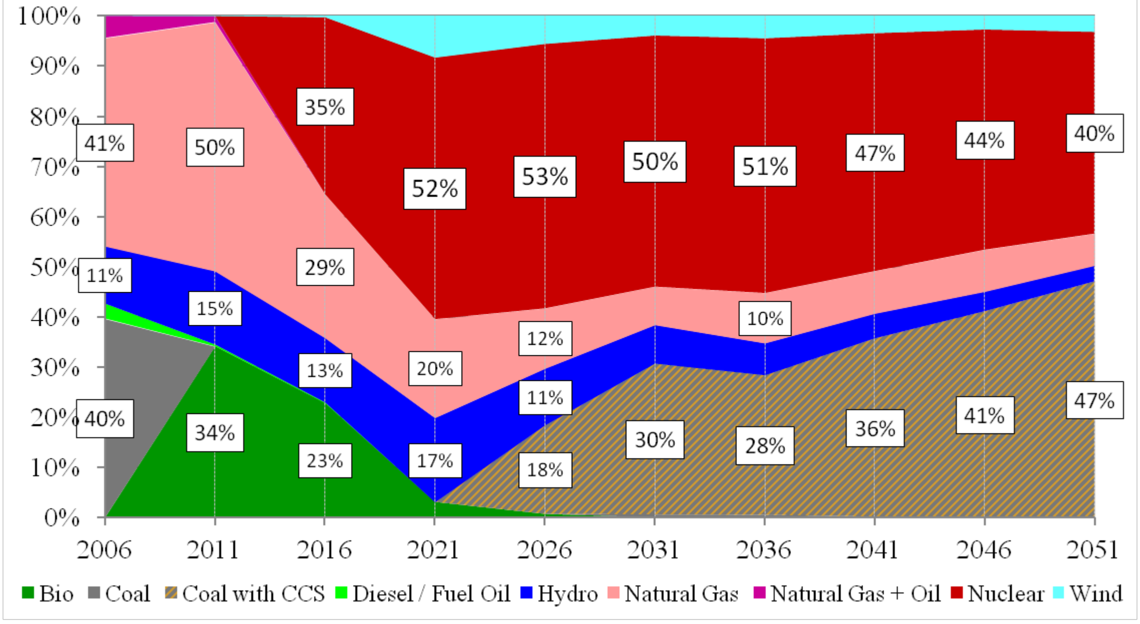

Figure 5.49. Breakdown of the primary energy resource consumed in electricity generation in the 50 per cent reduction, slow nuclear, fast CCS case

5.3.5.4. The 50 Per Cent Reduction, Slow Nuclear, Slow CCS Scenario.

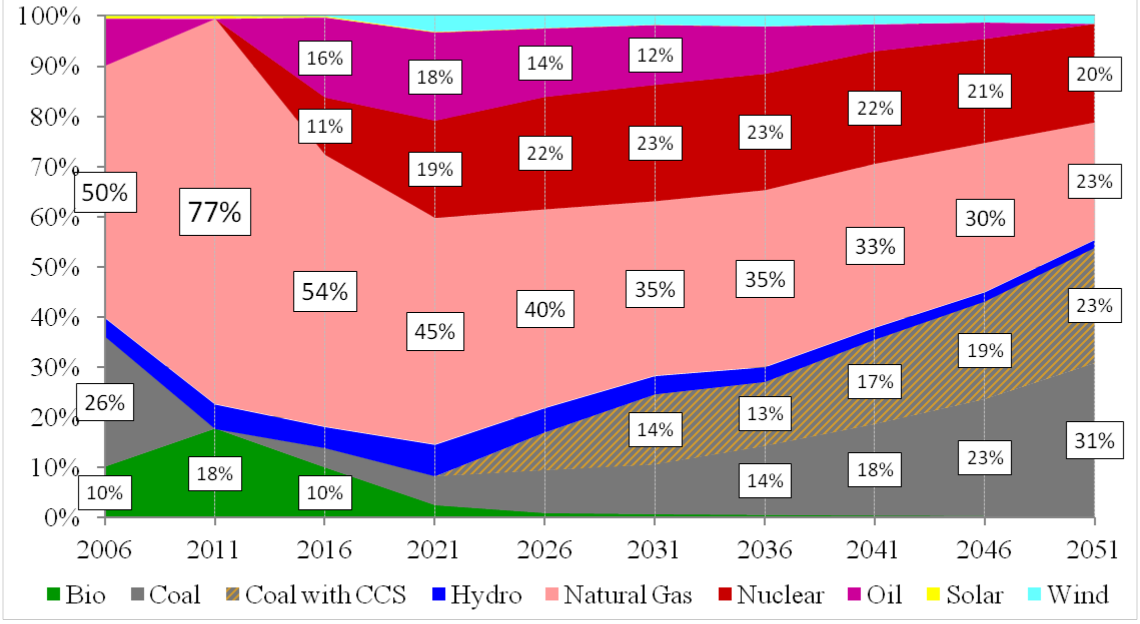

Figure 5.50. Breakdown of the primary energy resource consumption in the 50 per cent reduction, slow nuclear, slow CCS case

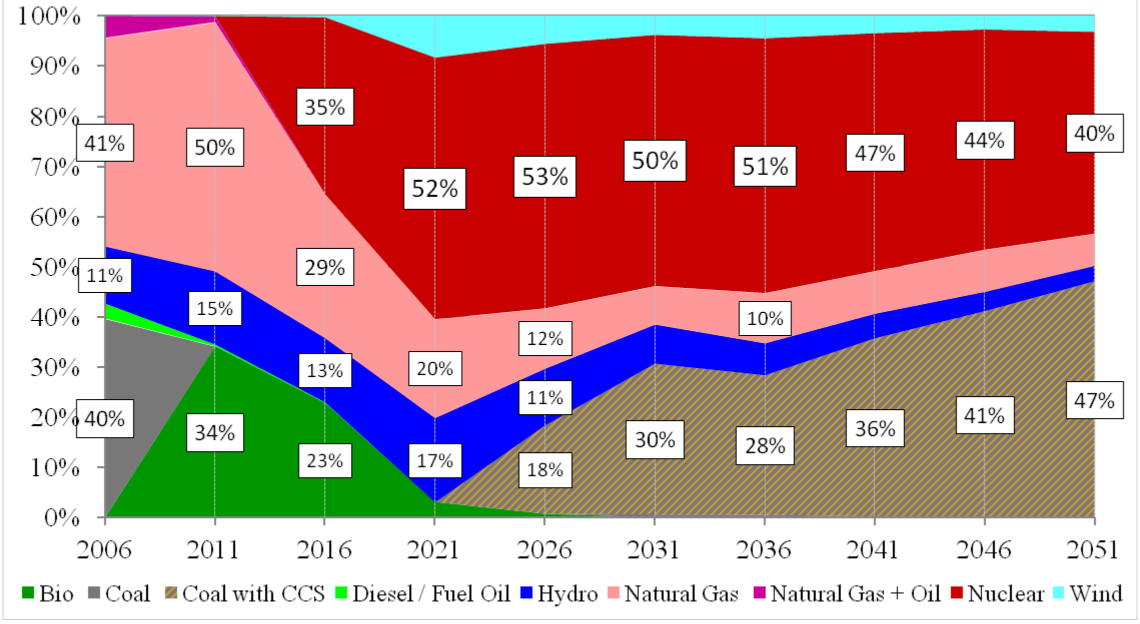

Figure 5.51. Breakdown of the primary energy resource consumed in electricity generation in the 50 per cent reduction, slow nuclear, slow CCS case

5.3.6. Comparison and Analysis of the Scenarios Constraining CO_2 Emissions Directly

In the policy scenarios featuring 20 per cent or more emissions reduction, it can be observed that nuclear power dominates in the “fast nuclear, slow CCS” and in the “fast nuclear fast CCS” scenarios. As the emission constraint gets stricter (i.e. higher emission reductions), the dominance of nuclear power increases —as much as 90 per cent share of primary energy in the GEN50_FS scenario. The “fast nuclear, slow CCS” and “fast nuclear, fast CCS” scenarios show a striking resemblance —especially in higher emissions reductions— since additional nuclear capacity investment has no upper limit in both cases. Note that the CCS investment is defined as a portion of the coal-based electricity production. Since CO_2 emissions of coal is very high, when there is a strict emissions constraint, it boils down to an all-or-nothing pattern for the share of CCS employment in coal-based electricity production. The all-CCS case is very costly and no-CCS case emits much CO_2. Thus, where the percentage reduction constraint is high, the nuclear energy investment is preferred over CCS and represses CCS investment especially when both are set free in an early time period (as in the “fast nuclear, fast CCS” scenario).

Common in all scenarios, oil usage diminishes over time and its reduction rate is correlated with the level set in emissions reductions. Considering the fact that it is both expensive and an all-import, its use abates with introduction of alternative technologies, such as electric battery– and hydrogen–powered vehicles.

Another point of interest is the spike caused by bio-energy in 2011 in scenarios of 50 per cent emission reduction. 2011 is a critical year because at that time, the emission constraint must be met and the nuclear and CCS technologies are not made available yet. With such a high-level emissions constraint the system cannot utilize coal, as it violates the constraint. Therefore, the system switches to higher use of natural gas and a significant deployment of bio energy —which is sourced by wood— , the cleanest of the available technologies in 2011. In the “fast nuclear” scenarios, with the introduction of no-upper-limit nuclear technology in 2016, the fuel switch to

Table 5.2. Total system cost and emissions in the scenarios constraining CO_2 emissions directly

Scenario	Cost (M TL/a)	CO_2 (kt/a)
GEN10_FF	73,416	236,206
GEN10_FS	73,228	236,206
GEN10_SF	73,495	236,206
GEN10_SS	73,269	236,206
GEN20_FF	73,571	209,961
GEN20_FS	73,413	209,961
GEN20_SF	73,573	209,961
GEN20_SS	73,475	209,961
GEN30_FF	73,829	183,716
GEN30_FS	73,698	183,716
GEN30_SF	74,541	183,716
GEN30_SS	74,435	183,716
GEN40_FF	74,228	157,471
GEN40_FS	74,225	157,471
GEN40_SF	76,513	157,471
GEN40_SS	76,513	157,471
GEN50_FF	76,388	131,225
GEN50_FS	76,389	131,225
GEN50_SF	79,258	131,225
GEN50_SS	79,258	131,225

nuclear power is very swift and natural gas use decreases accordingly.

Table 5.2 portrays the average annual system cost and emissions amount associated with each scenario in the scenario group constraining CO_2 emissions directly. The increasing cost with increased rates of CO_2 emission mitigation can be observed clearly. In addition, “slow nuclear” scenarios prove more costly than “fast nuclear” scenarios, due to the limitation of the relatively cheap and clean nuclear power to an installment of 1GW every five years. The cost difference between "slow nuclear" and "high nuclear" scenarios peaks when the emissions constraint is at 50 per cent level because of the extensive obligatory use of the expensive CCS technology, both in the "slow nuclear, fast CCS" and in the "slow nuclear, slow CCS" scenarios.

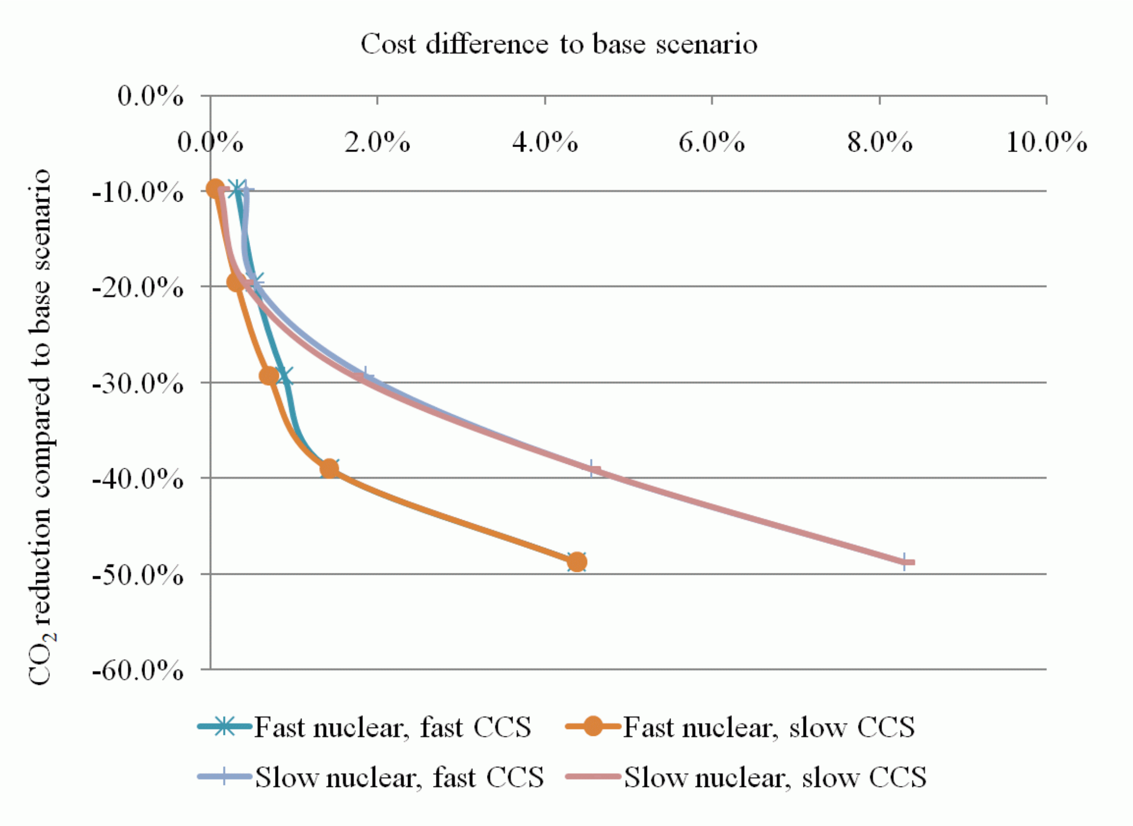

Figure 5.52. System cost comparisons of the scenarios constraining CO_2 emissions directly to the base scenario

Figure 5.3.6 displays the additional system costs brought about by different emissions reduction scenarios under various nuclear and CCS options, in comparison to the base scenario. As the emissions constraint gets stricter, the costs of "fast" and "slow" CCS scenarios converge into each other when the level of nuclear investment is identical, because of the all-or-nothing investment behavior of the CCS technology. Note that the "fast nuclear, slow CCS" scenario family gives the minimum cost increase in every level of the emission constraint because it allows unlimited use of economical and clean nuclear power while enforcing less CCS use, which is the propitious combination.

5.4. Scenarios Discouraging CO_2 Emissions through Taxes (Penalties)

5.4.1. The 10 TL Tax per ton of CO_2 Emission Scenarios

Figures 5.4.1.1 and 5.4.1.1 show the breakdown of the primary energy consumption and primary energy resource consumed in electricity generation in the 10 TL tax per ton emissions reduction scenario with the “fast nuclear, fast CCS” parameters. It can be seen that from 2016 onwards, the share of nuclear energy consumption increases rapidly, peaking in the year 2031. After 2031, the share of coal consumption increases, because the system prefers paying tax over investing in nuclear energy. This behavior can be observed to change, as higher levels of tax are applied. Despite the fact that there is no upper limit defined in “fast nuclear” scenarios, the maximum share attained by nuclear energy is 69 per cent in 2031. It can also be seen that by the year 2031 nuclear energy captures most of the share of natural gas. After 2031, the share of nuclear energy decreases, while coal energy consumption is on the rise. The CCS investments are only due to the fulfillment of the minimum constraints.

In the “fast nuclear, slow CCS” scenario (Figures 5.4.1.2 and 5.4.1.2), the share of coal consumption after the year 2031 is about 10 per cent higher than in the “fast nuclear, fast CCS” scenario, while the share of nuclear energy is about the same. The increasing share of coal consumption is balanced with the decreasing share of natural gas consumption.

In the scenarios where nuclear investments are limited (the slow nuclear scenarios), the energy breakdown figures are very similar, independent of the CCS investment factor level —as shown in Figures 5.4.1.3, 5.4.1.3, 5.4.1.4 and 5.4.1.4. Nuclear energy consumption is limited, and it provides one-third of the primary energy resource consumed in electricity generation, by the year 2036. Both in the “fast CCS” and the “slow CCS” scenarios, the coal consumption portrays a steady increase. The only difference between these two scenarios is the amount of CCS investment. The lower CCS investment levels in the “slow CCS scenario” results in the diminishing share of natural gas consumption, from the year 2051 onwards.

5.4.1.1. The 10 TL Tax per ton of CO_2, Fast Nuclear, Fast CCS Scenario.

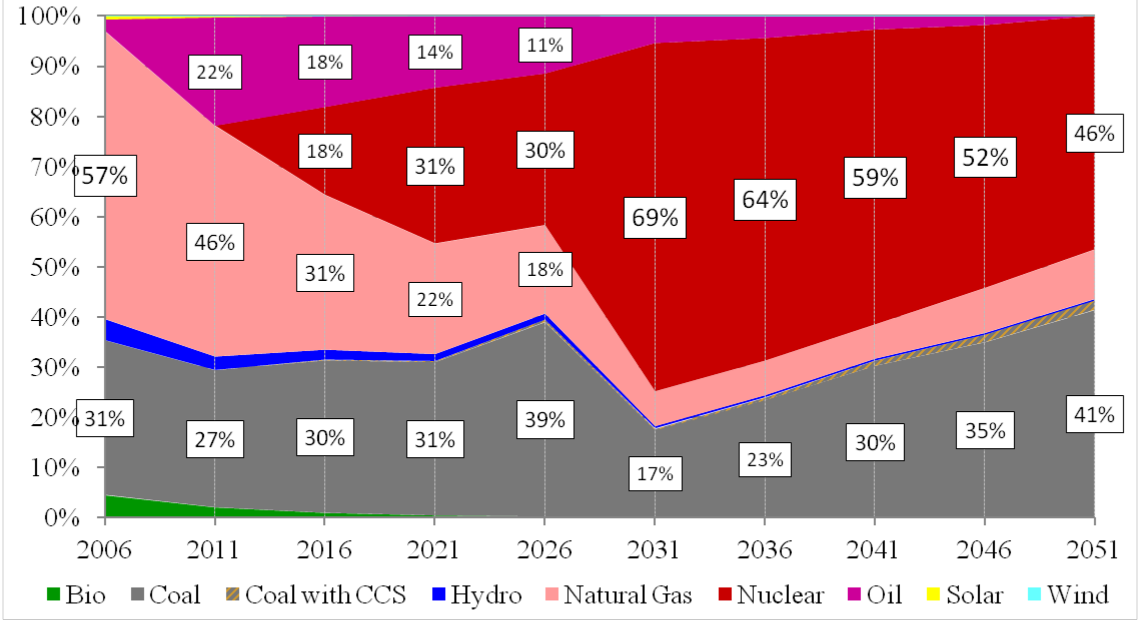

Figure 5.53. Breakdown of the primary energy resource consumption in the 10 TL tax per ton of CO_2, fast nuclear, fast CCS case

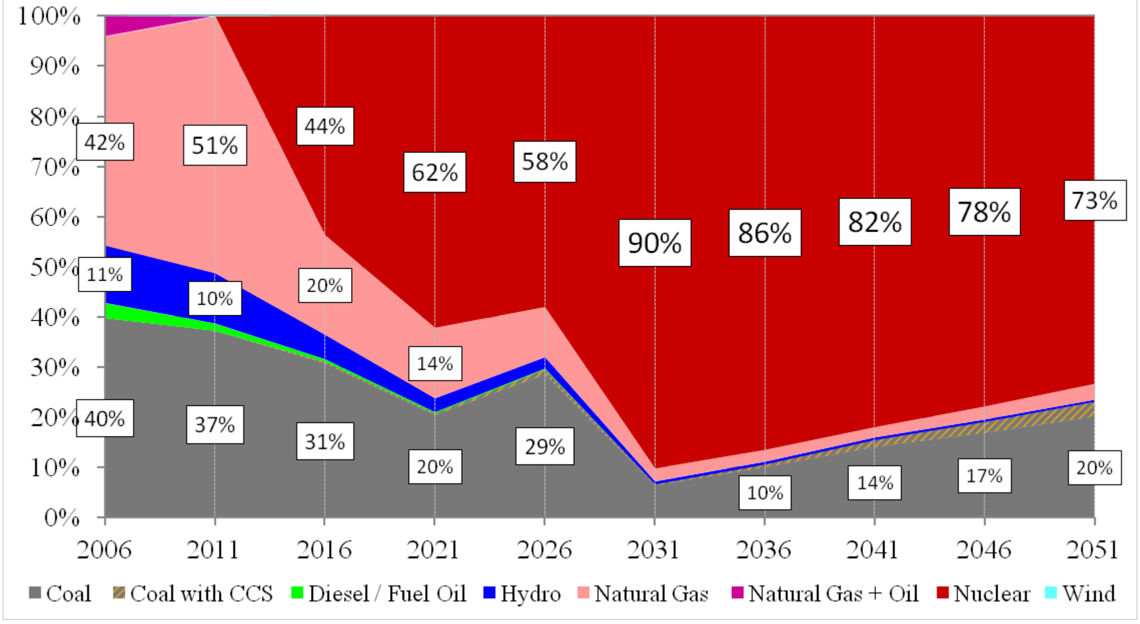

Figure 5.54. Breakdown of the primary energy resource consumed in electricity generation in the 10 TL tax per ton of CO_2, fast nuclear, fast CCS case

5.4.1.2. The 10 TL Tax per ton of CO_2, Fast Nuclear, Slow CCS Scenario.

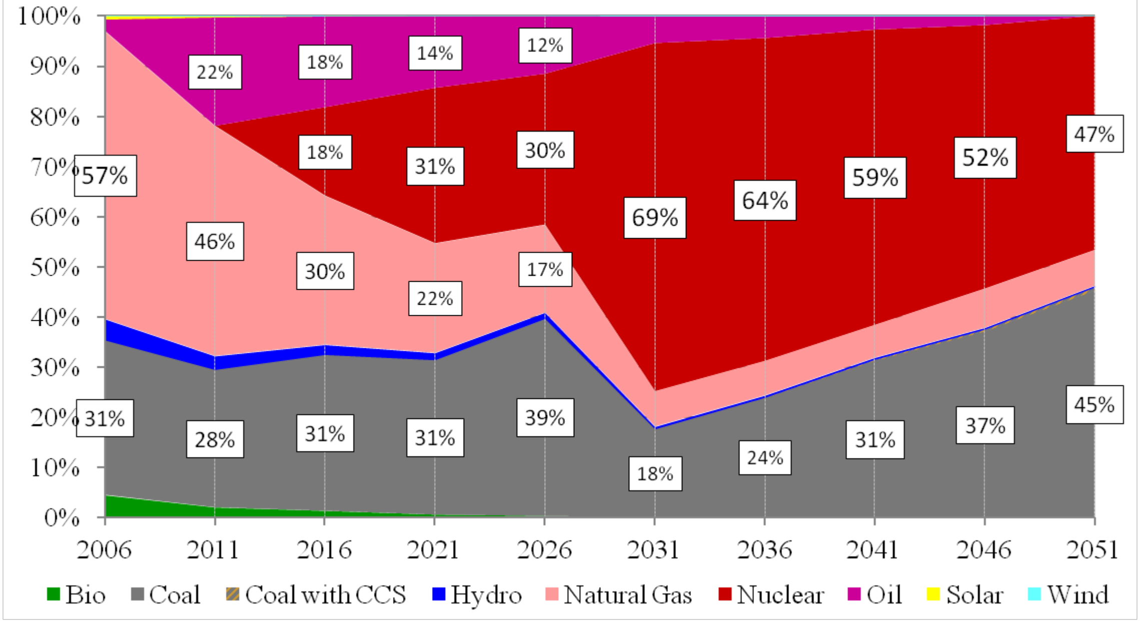

Figure 5.55. Breakdown of the primary energy resource consumption in the 10 TL tax per ton of CO_2, fast nuclear, slow CCS case

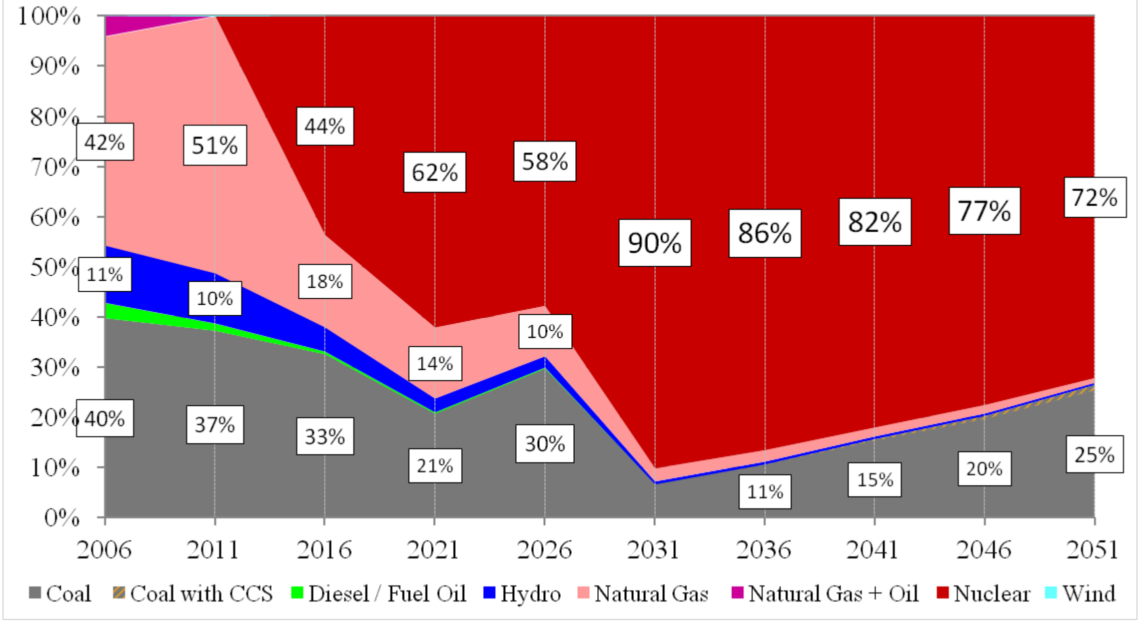

Figure 5.56. Breakdown of the primary energy resource consumed in electricity generation in the 10 TL tax per ton of CO_2, fast nuclear, slow CCS case

5.4.1.3. The 10 TL Tax per ton of CO_2, Slow Nuclear, Fast CCS Scenario.

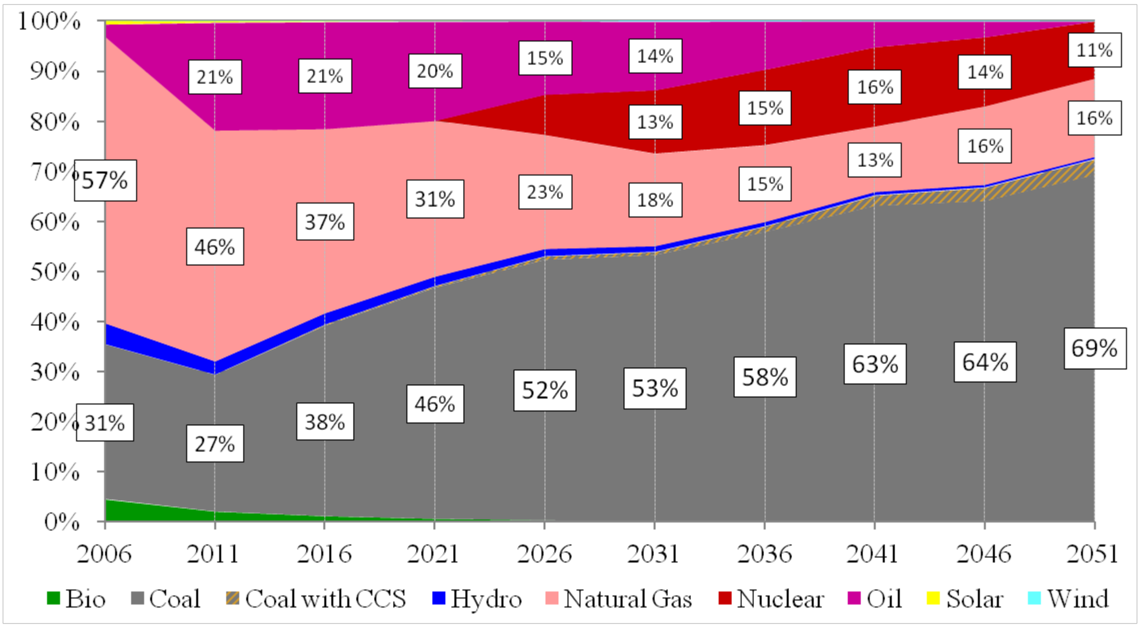

Figure 5.57. Breakdown of the primary energy resource consumption in the 10 TL tax per ton of CO_2, slow nuclear, fast CCS case

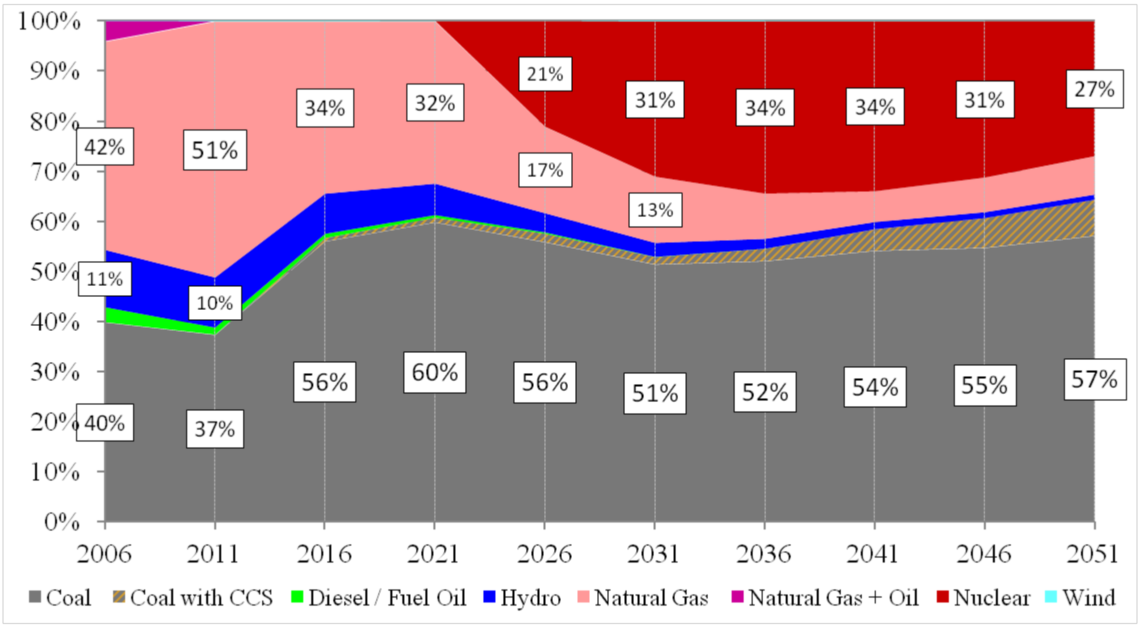

Figure 5.58. Breakdown of the primary energy resource consumed in electricity generation in the 10 TL tax per ton of CO_2, slow nuclear, fast CCS case

5.4.1.4. The 10 TL Tax per ton of CO_2, Slow Nuclear, Slow CCS Scenario.

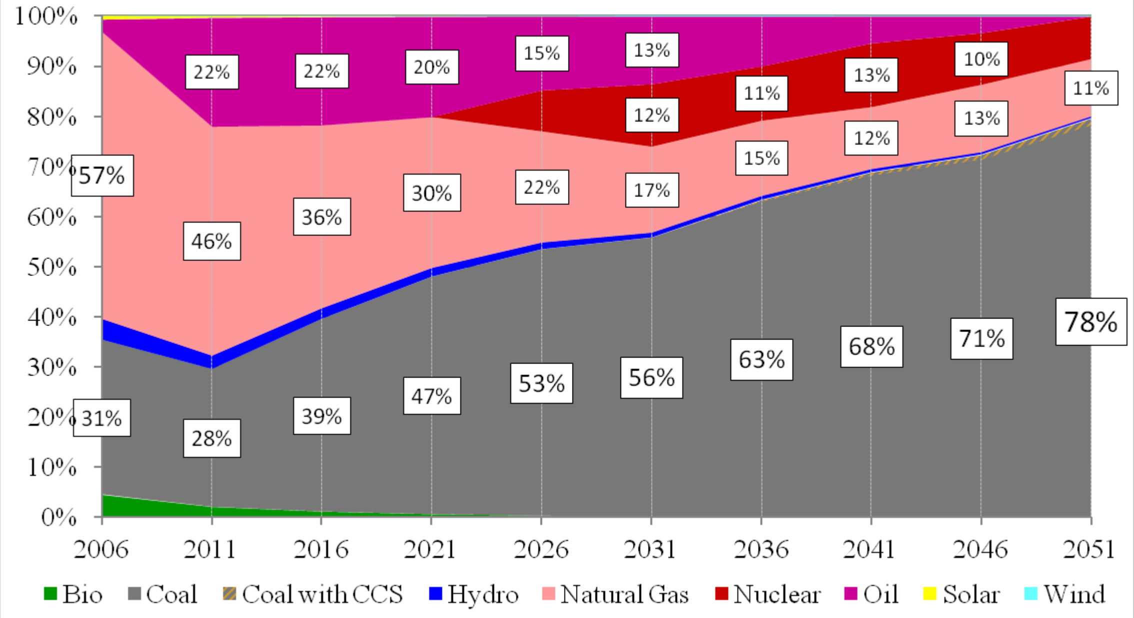

Figure 5.59. Breakdown of the primary energy resource consumption in the 10 TL tax per ton of CO_2, slow nuclear, slow CCS case

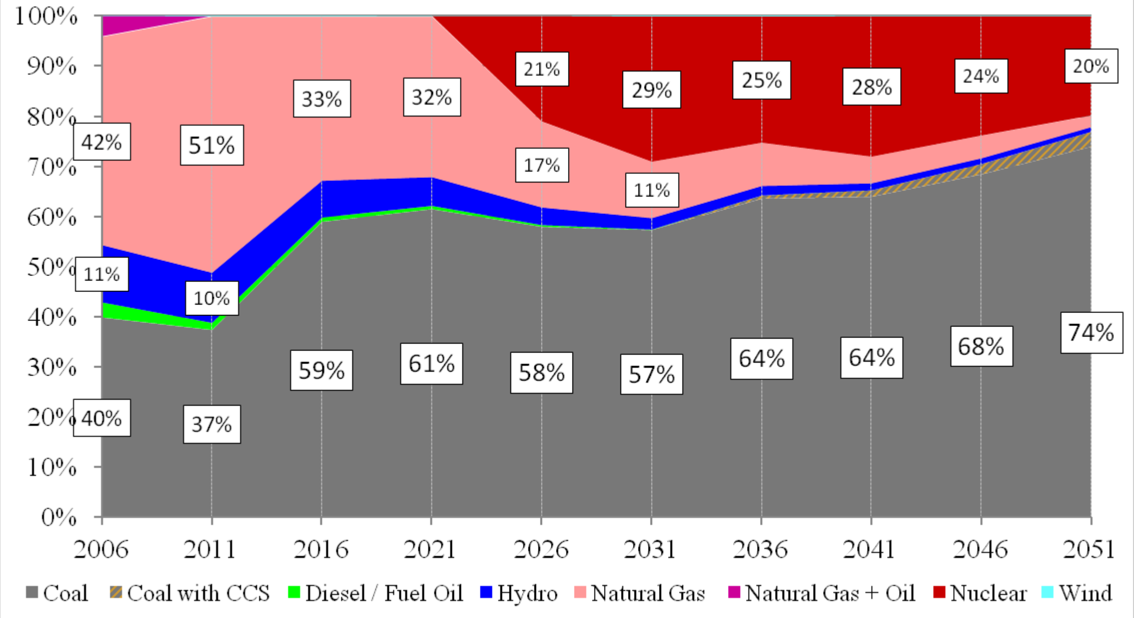

Figure 5.60. Breakdown of the primary energy resource consumed in electricity generation in the 10 TL tax per ton of CO_2, slow nuclear, slow CCS case

5.4.2. The 20 TL Tax per ton of CO_2 Emission Scenarios

In the “fast nuclear, fast CCS” scenario a rapid increase in the share of nuclear power can ben seen from the year 2016 onwards (Figures 5.4.2.1 and 5.4.2.1). With this rapid increase, the share of nuclear power in primary energy consumption becomes 79 per cent in 2031. After this point, the rate of increase regarding the share of nuclear power is lower, the share of nuclear power in primary energy consumption becomes 88 per cent by 2051. Also, after 2031, the share of natural gas consumption stays below the five per cent mark. In the year 2011, natural gas and coal consumption generate 88 per cent of the required electricity (nuclear investments are not allowed until 2016). Coal consumption does not exceed one-fourth of the total energy consumption.

The energy breakdown regarding the “fast nuclear, slow CCS” scenario (shown in Figures 5.4.2.2 and 5.4.2.2) is similar to the “fast nuclear, fast CCS” scenario. Since coal consumption is at a low level after the year 2031, the decreased investment rate of the CCS technology does not cause a significant change in the energy breakdown. Beginning from 2031, the nuclear energy consumption heavily dominates electricity generation, having a share of 93 per cent in 2031 and reaching 99 per cent of the electricity generation by 2051.

In both of the “slow nuclear” scenarios, the nuclear energy consumption does not exceed one-sixth of the total primary energy consumption, as shown in Figures 5.4.2.3, 5.4.2.3, 5.4.2.4 and 5.4.2.4. The share of coal consumption increases linearly throughout the period 2011–2051, reaching 64 per cent by 2051. Natural gas consumption maintains its primary energy consumption share of 18 per cent throughout the period 2031–2051. The share of oil consumption starts to decrease by 2021 and is kept significant until 2041.

5.4.2.1. The 20 TL Tax per ton of CO_2, Fast Nuclear, Fast CCS Scenario.

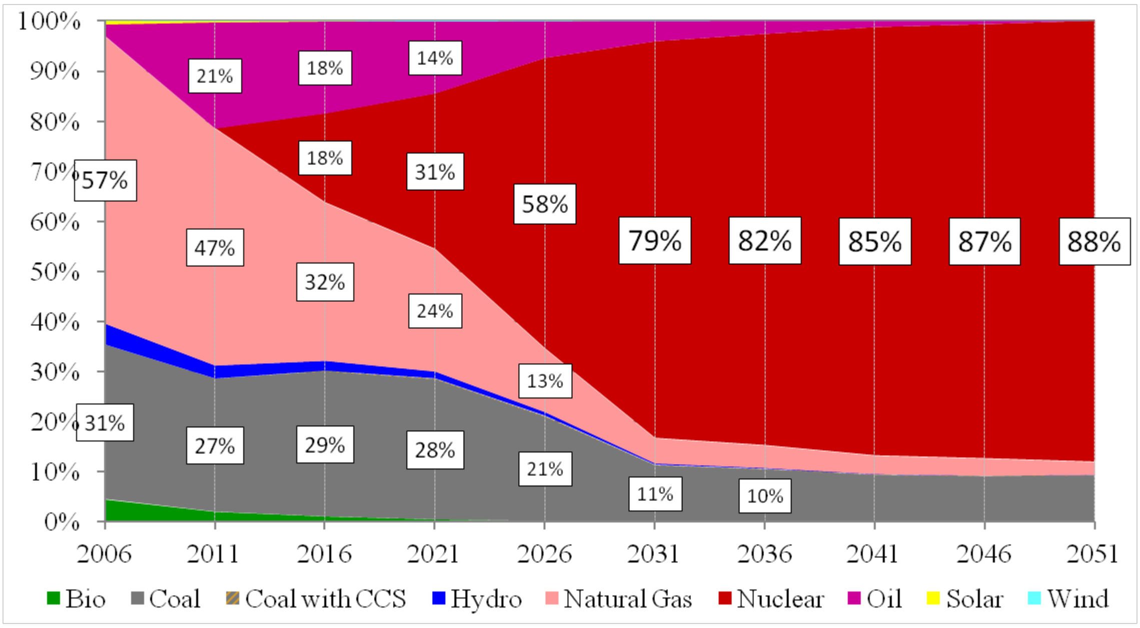

Figure 5.61. Breakdown of the primary energy resource consumption in the 20 TL tax per ton of CO_2, fast nuclear, fast CCS case

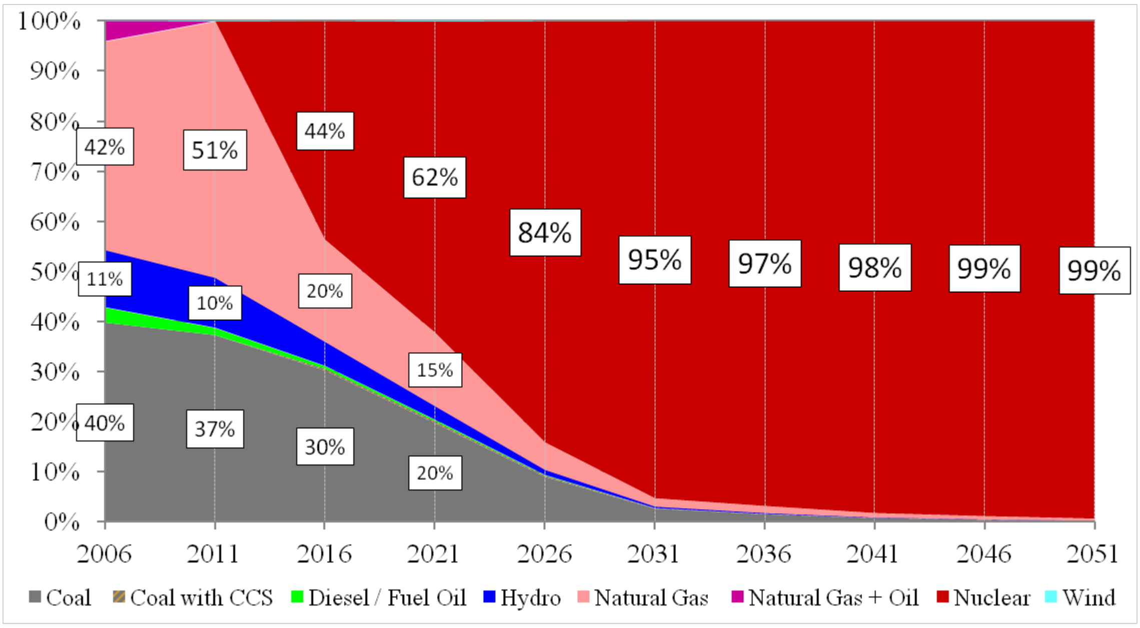

Figure 5.62. Breakdown of the primary energy resource consumed in electricity generation in the 20 TL tax per ton of CO_2, fast nuclear, fast CCS case

5.4.2.2. The 20 TL Tax per ton of CO_2, Fast Nuclear, Slow CCS Scenario.

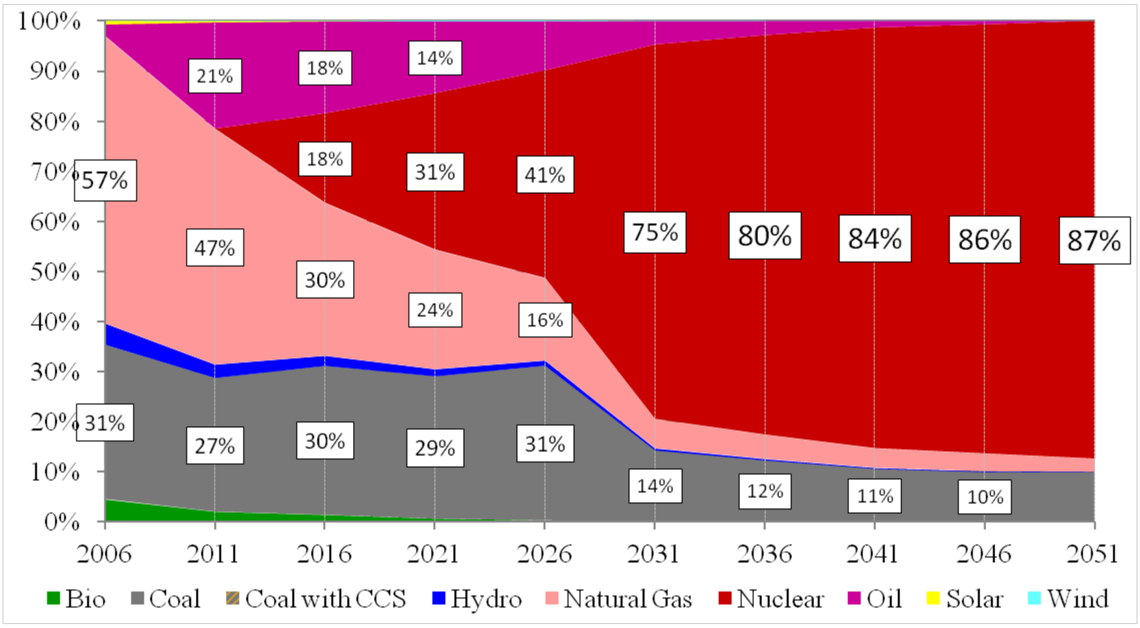

Figure 5.63. Breakdown of the primary energy resource consumption in the 20 TL tax per ton of CO_2, fast nuclear, slow CCS case

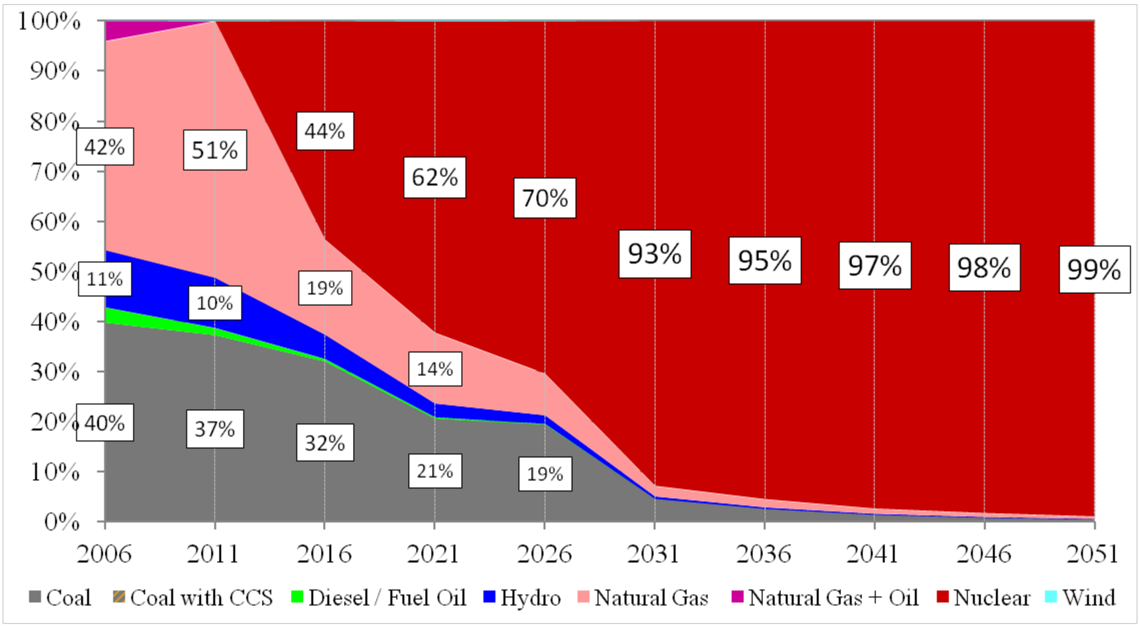

Figure 5.64. Breakdown of the primary energy resource consumed in electricity generation in the 20 TL tax per ton of CO_2, fast nuclear, slow CCS case

5.4.2.3. The 20 TL Tax per ton of CO_2, Slow Nuclear, Fast CCS Scenario.

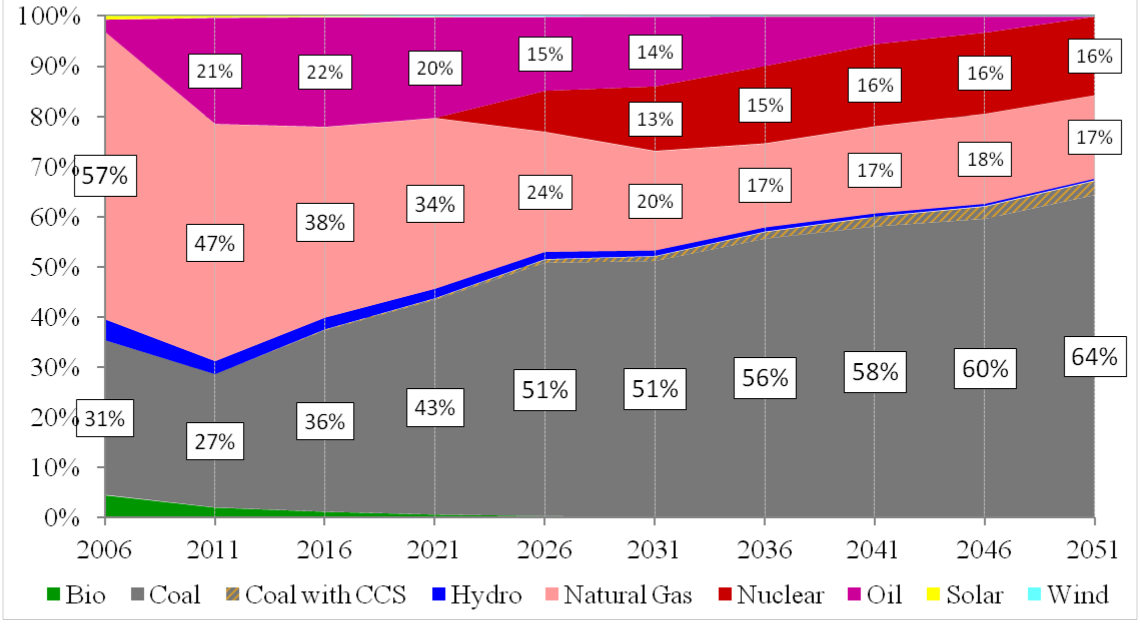

Figure 5.65. Breakdown of the primary energy resource consumption in the 20 TL tax per ton of CO_2, slow nuclear, fast CCS case

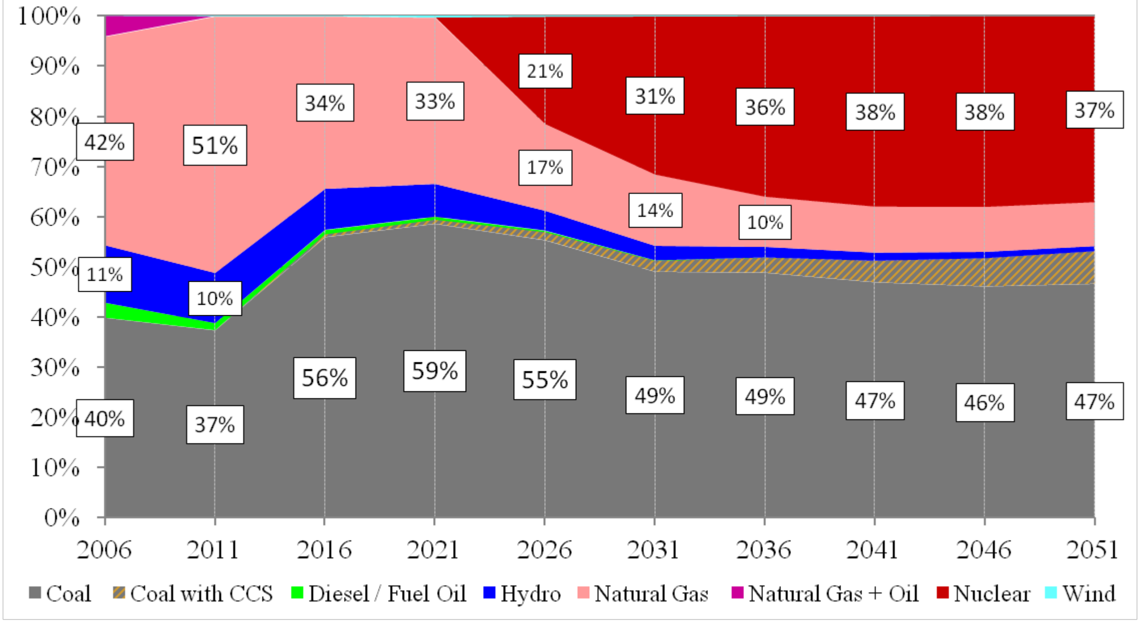

Figure 5.66. Breakdown of the primary energy resource consumed in electricity generation in the 20 TL tax per ton of CO_2, slow nuclear, fast CCS case

5.4.2.4. The 20 TL Tax per ton of CO_2, Slow Nuclear, Slow CCS Scenario.

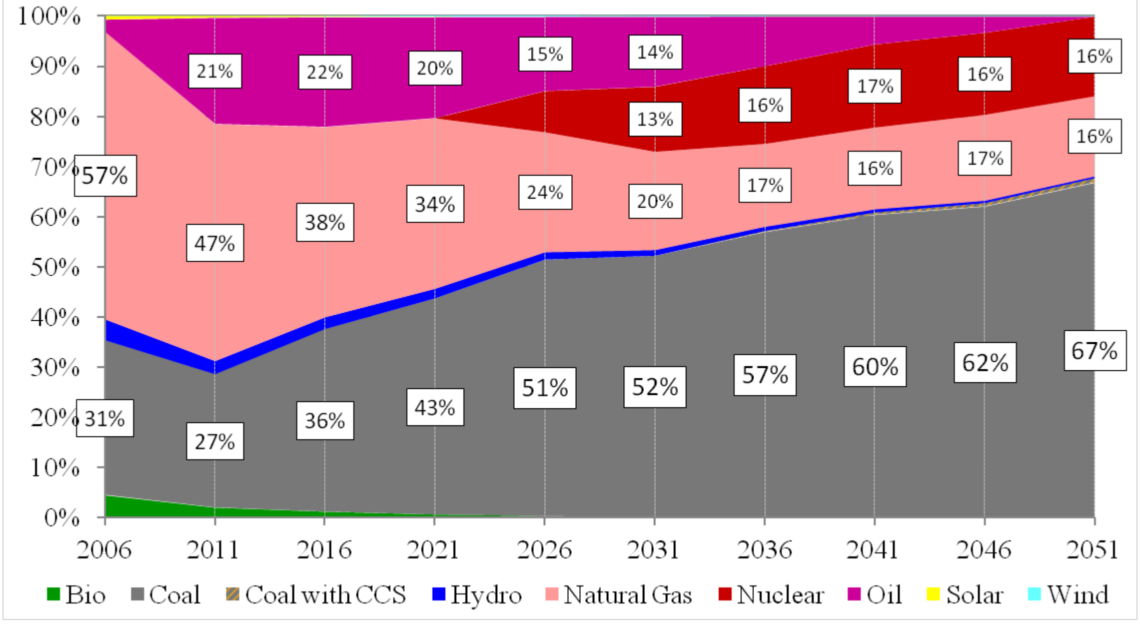

Figure 5.67. Breakdown of the primary energy resource consumption in the 20 TL tax per ton of CO_2, slow nuclear, slow CCS case

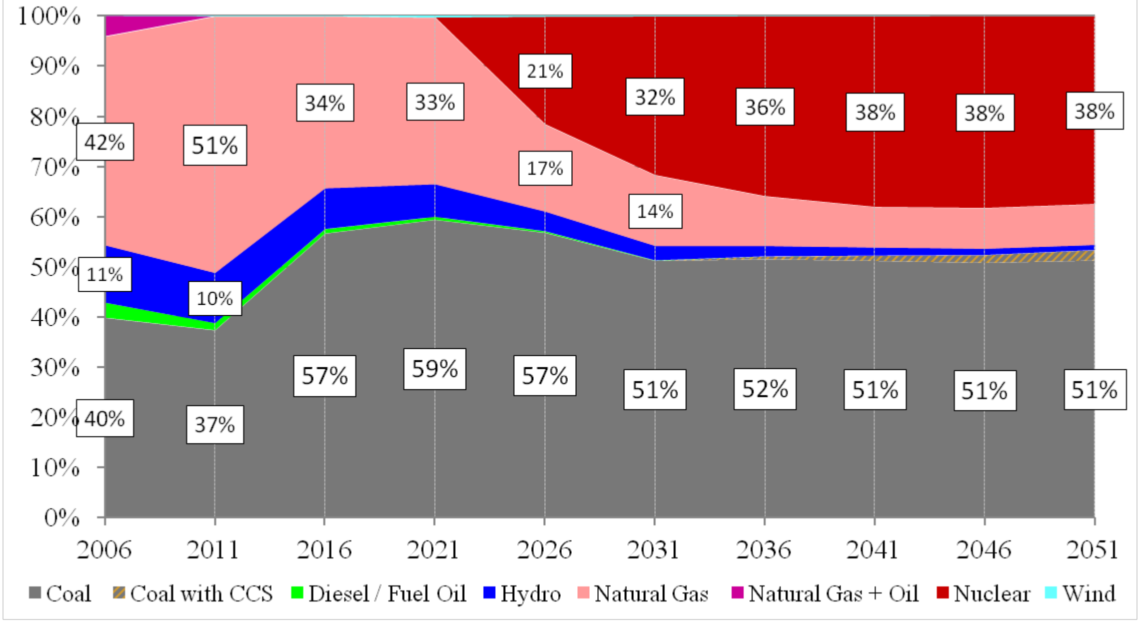

Figure 5.68. Breakdown of the primary energy resource consumed in electricity generation in the 20 TL tax per ton of CO_2, slow nuclear, slow CCS case

5.4.3. The 30 TL Tax per ton of CO_2 Emission Scenarios

The “fast nuclear, fast CCS” scenario mainly utilizes nuclear power from the year 2026 onwards (Figures 5.4.3.1 and 5.4.3.1). After 2026, the share of coal in primary energy consumption is kept below 15 per cent. In the year 2011, natural gas and coal consumption generate 88 per cent of the electricity (nuclear investments are not allowed until 2016). From 2026 onwards, the nuclear energy consumption heavily dominates the electricity generation and after 2036, nuclear power plants provide all of the electricity supply.

The energy breakdown regarding the “fast nuclear, slow CCS” scenario is quite similar to the “fast nuclear, fast CCS” scenario (Figures 5.4.3.2 and 5.4.3.2). The variation in the level of CCS technology investments does not make a difference, since the share of coal consumption is low, especially after 2026 (less than one-tenth of the primary energy consumption).

In the “slow nuclear” scenarios, the nuclear power does not exceed one-fifth of the total primary energy consumption, as shown in Figures 5.4.3.3, 5.4.3.3, 5.4.3.4 and 5.4.3.4. Although the share of coal consumption increases linearly through the period 2011–2051, the increase is less than the corresponding 20 TL tax per ton scenarios, reaching 62 per cent by 2051. Natural gas consumption maintains its 18 per cent share in primary energy consumption through the period 2031–2051. In 2011, before the availability of nuclear investments, 51 per cent of the electricity is generated through natural gas and another 37 per cent is generated through coal. Also, in the “slow nuclear, fast CCS” scenario, the share of the CCS-supported coal consumption in electricity generation is significant (but does not exceed 10 per cent), especially after 2046.

5.4.3.1. The 30 TL Tax per ton of CO_2, Fast Nuclear, Fast CCS Scenario.

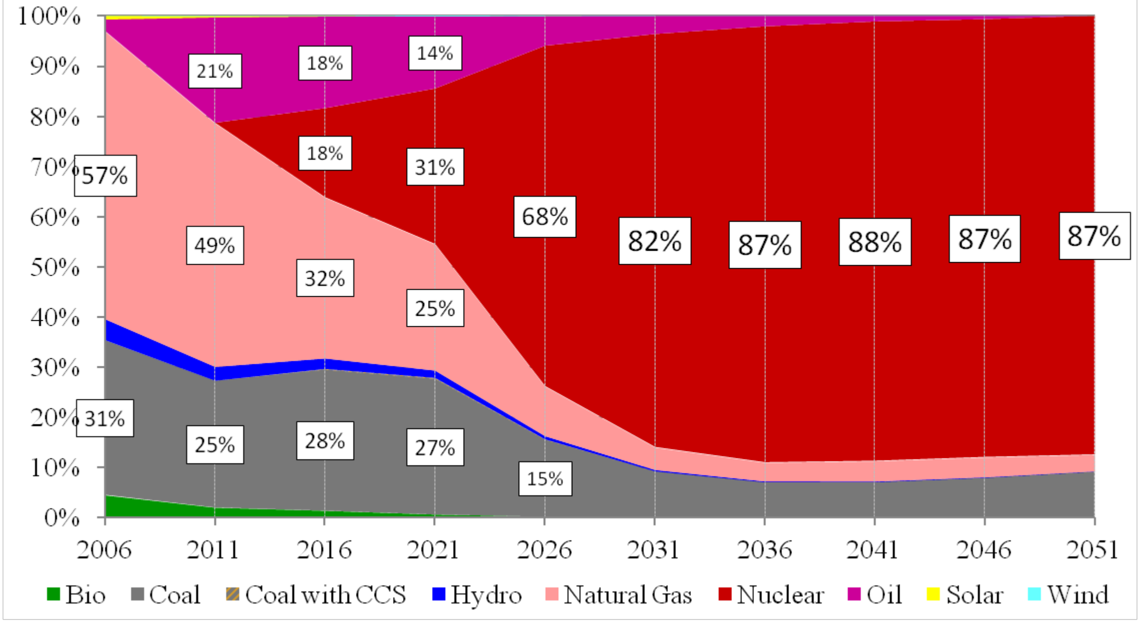

Figure 5.69. Breakdown of the primary energy resource consumption in the 30 TL tax per ton of CO_2, fast nuclear, fast CCS case

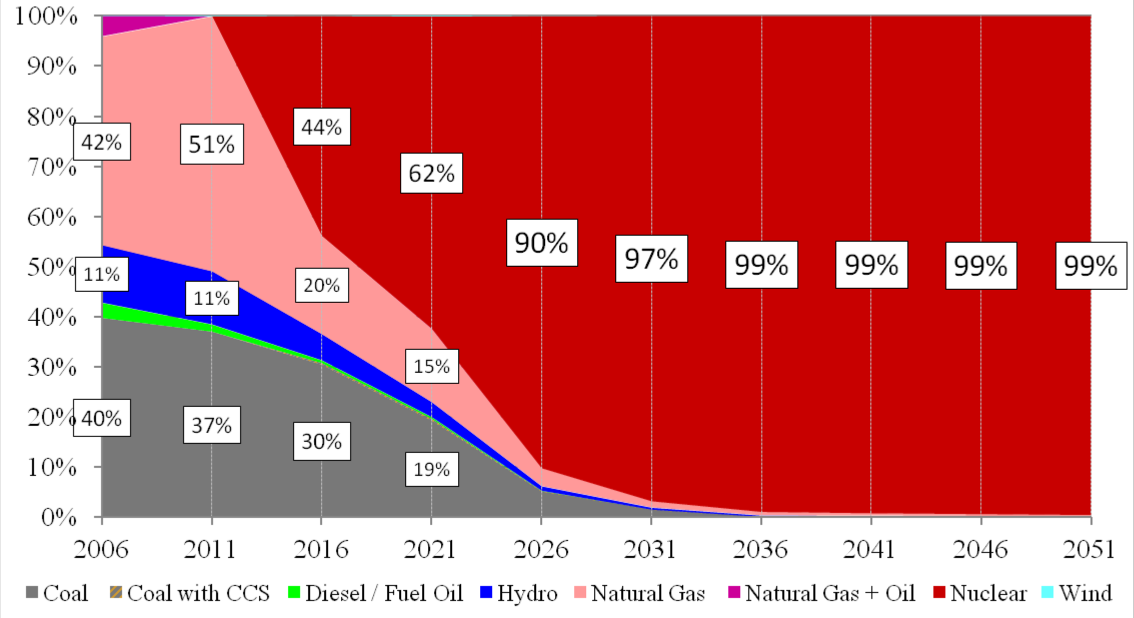

Figure 5.70. Breakdown of the primary energy resource consumed in electricity generation in the 30 TL tax per ton of CO_2, fast nuclear, fast CCS case

5.4.3.2. The 30 TL Tax per ton of CO_2, Fast Nuclear, Slow CCS Scenario.

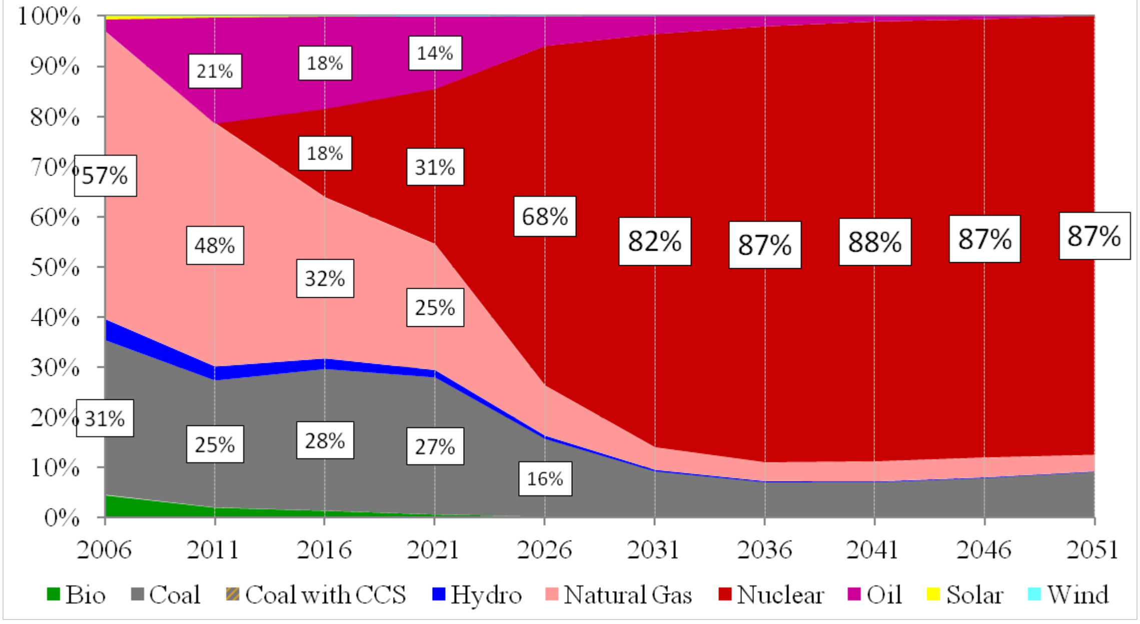

Figure 5.71. Breakdown of the primary energy resource consumption in the 30 TL tax per ton of CO_2, fast nuclear, slow CCS case

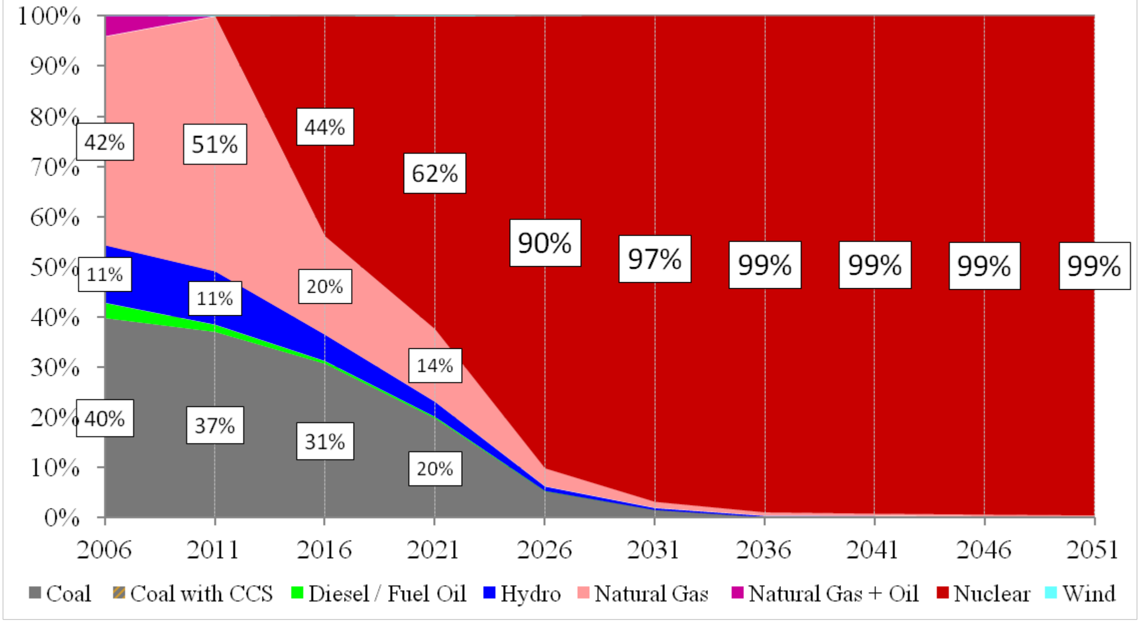

Figure 5.72. Breakdown of the primary energy resource consumed in electricity generation in the 30 TL tax per ton of CO_2, fast nuclear, slow CCS case

5.4.3.3. The 30 TL Tax per ton of CO_2, Slow Nuclear, Fast CCS Scenario.

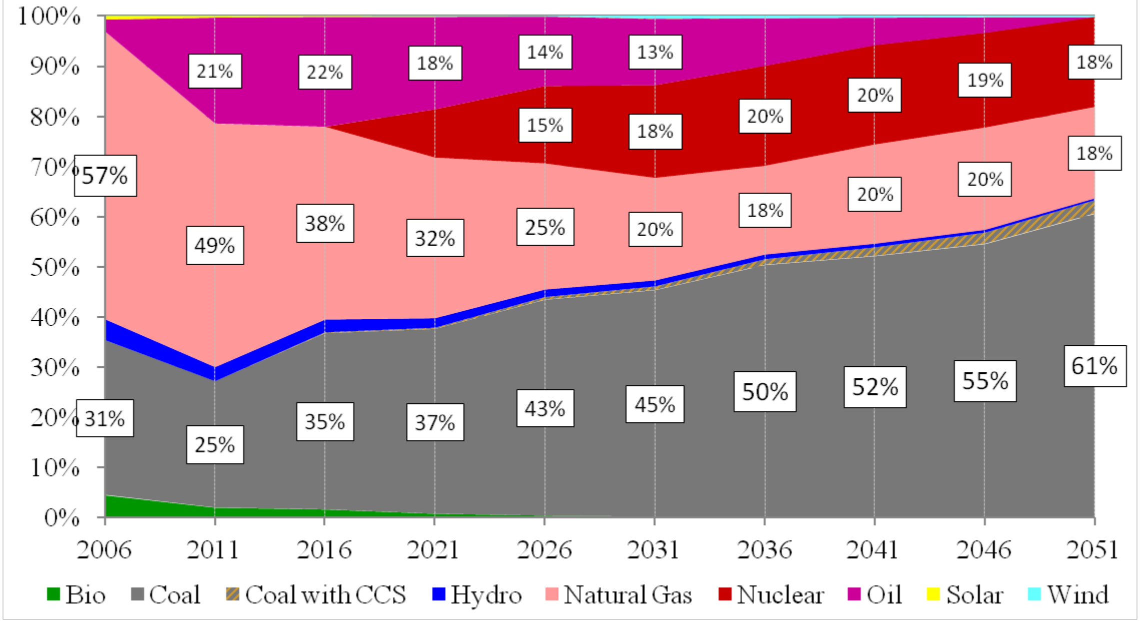

Figure 5.73. Breakdown of the primary energy resource consumption in the 30 TL tax per ton of CO_2, slow nuclear, fast CCS case

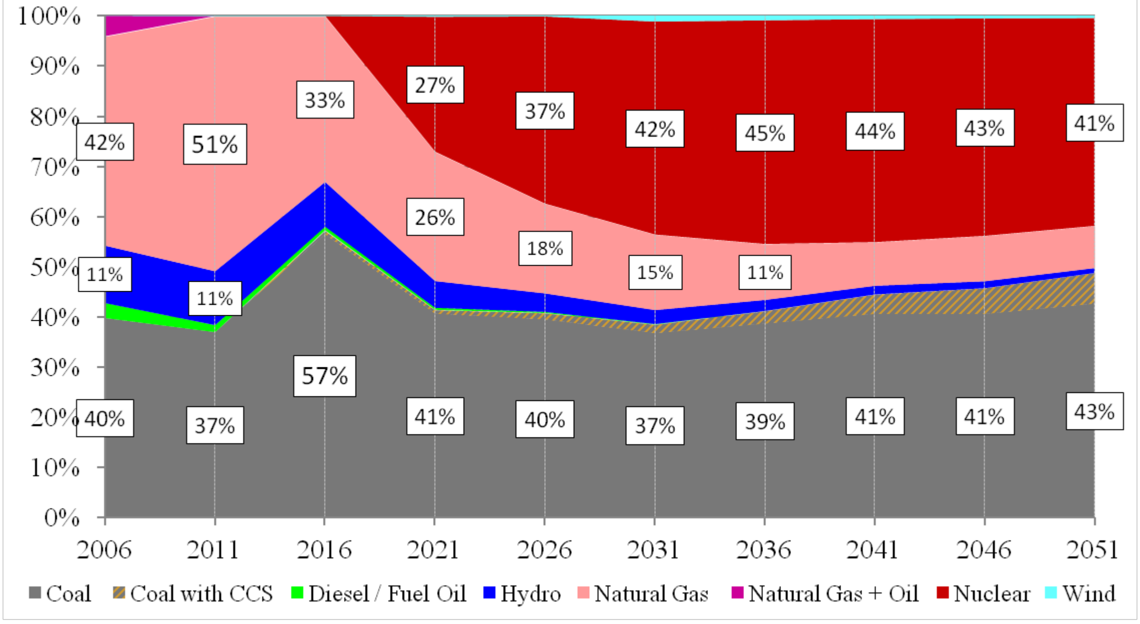

Figure 5.74. Breakdown of the primary energy resource consumed in electricity generation in the 30 TL tax per ton of CO_2, slow nuclear, fast CCS case

5.4.3.4. The 30 TL Tax per ton of CO_2, Slow Nuclear, Slow CCS Scenario.

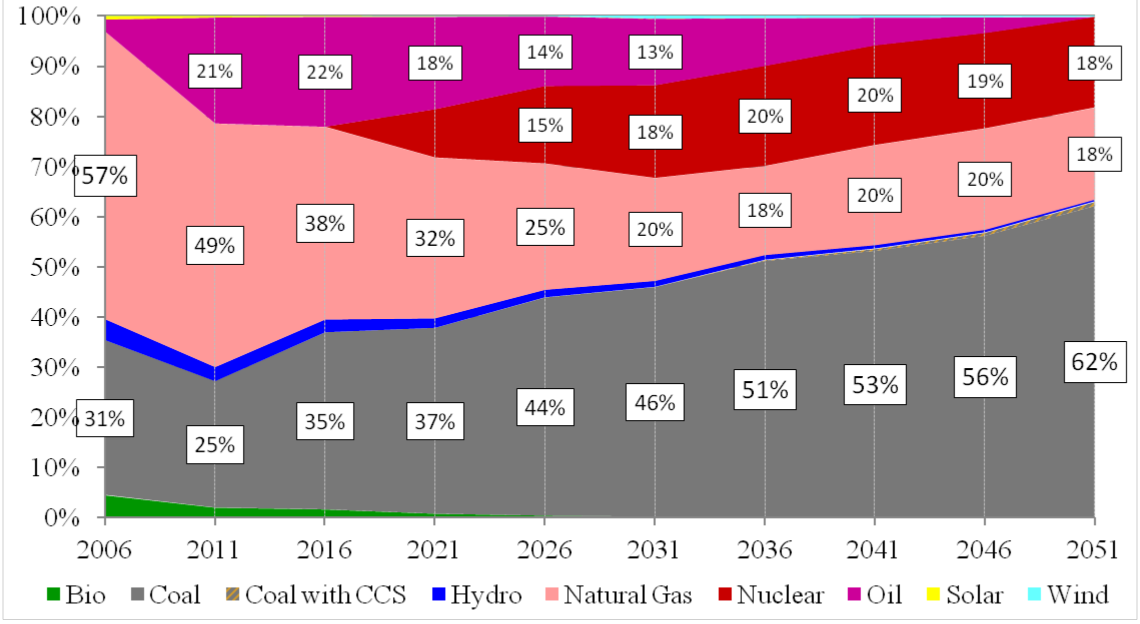

Figure 5.75. Breakdown of the primary energy resource consumption in the 30 TL tax per ton of CO_2, slow nuclear, slow CCS case

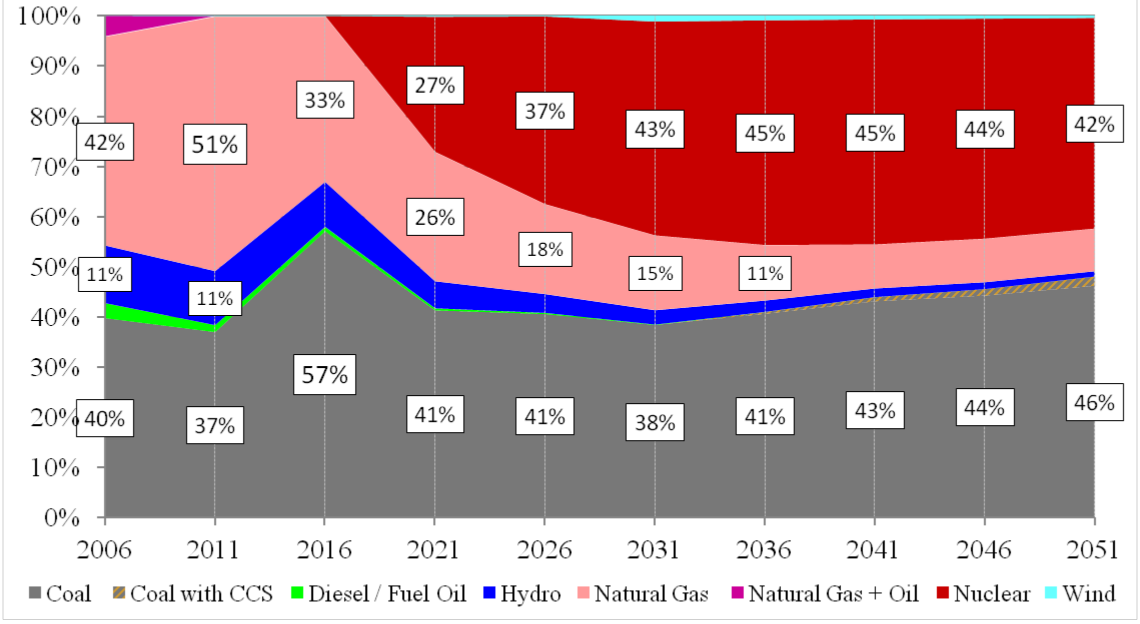

Figure 5.76. Breakdown of the primary energy resource consumed in electricity generation in the 30 TL tax per ton of CO_2, slow nuclear, slow CCS case

5.4.4. The 40 TL Tax per ton of CO_2 Emission Scenarios

Both in the breakdown of the primary energy consumption and in the breakdown of the energy used in electricity generation, the “fast nuclear, fast CCS” and “fast nuclear, slow CCS” scenarios are very similar (Figures 5.4.4.1, 5.4.4.1, 5.4.4.2 and 5.4.4.2), since coal consumption does not exceed 10 per cent of the primary energy needs after 2026 and accordingly the levels of CCS investment do not have any significant effect on the energy breakdown figures. In the year 2011, natural gas and coal are consumed to generate together 86 per cent of the electricity (nuclear investments are not allowed until 2016). In the period 2011–2026, the share of natural gas in primary energy consumption falls rapidly and becomes less than 10 per cent, from 2026 onwards. From 2031 onwards, about all of the electricity generation is due to the use of nuclear power.

In the “slow nuclear” scenarios, the nuclear energy consumption does not exceed one-fourth of the total primary energy needs, as shown in Figures 5.4.4.3, 5.4.4.3, 5.4.4.4 and 5.4.4.4. The share of coal consumption increases linearly through the period 2011–2051, reaching 58 per cent by 2051. The CCS investments are only due to the fulfillment of the minimum requirements and do not exceed eight per cent in the “slow nuclear, fast CCS” scenario. In 2011, before the availability of nuclear investments, 54 per cent of the electricity is generated through natural gas, while 32 per cent is generated through coal, accounting for the 86 per cent of total electricity generation together. Then, the share of natural gas consumption as a primary energy resource declines throughout the whole timespan, but still manages to stand at 20 per cent by 2051.

5.4.4.1. The 40 TL Tax per ton of CO_2, Fast Nuclear, Fast CCS Scenario.

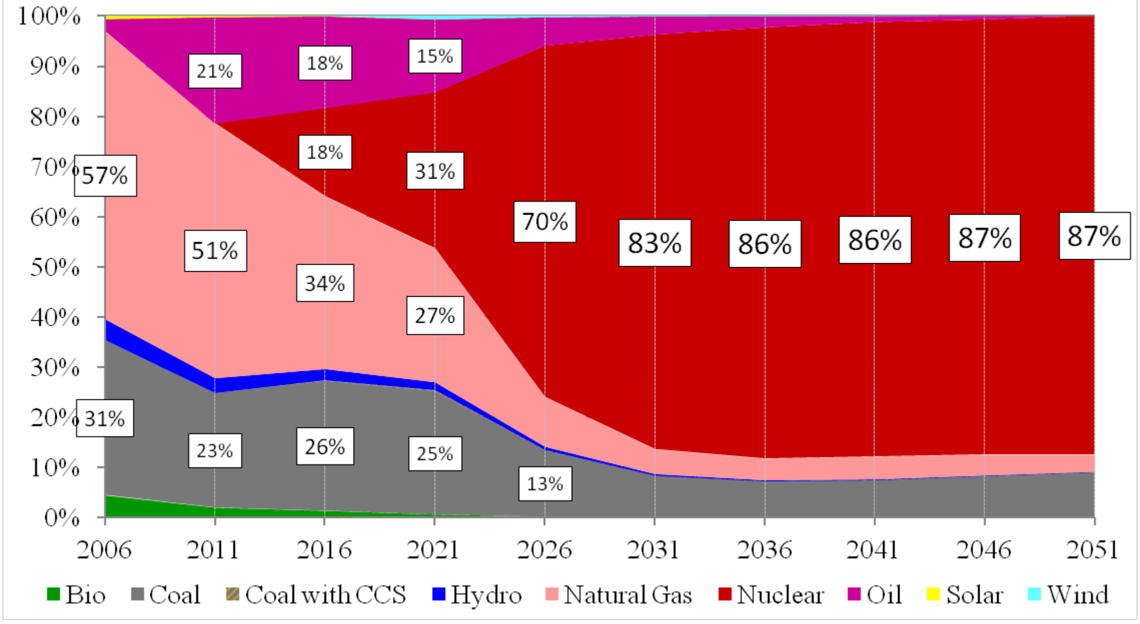

Figure 5.77. Breakdown of the primary energy resource consumption in the 40 TL tax per ton of CO_2, fast nuclear, fast CCS case

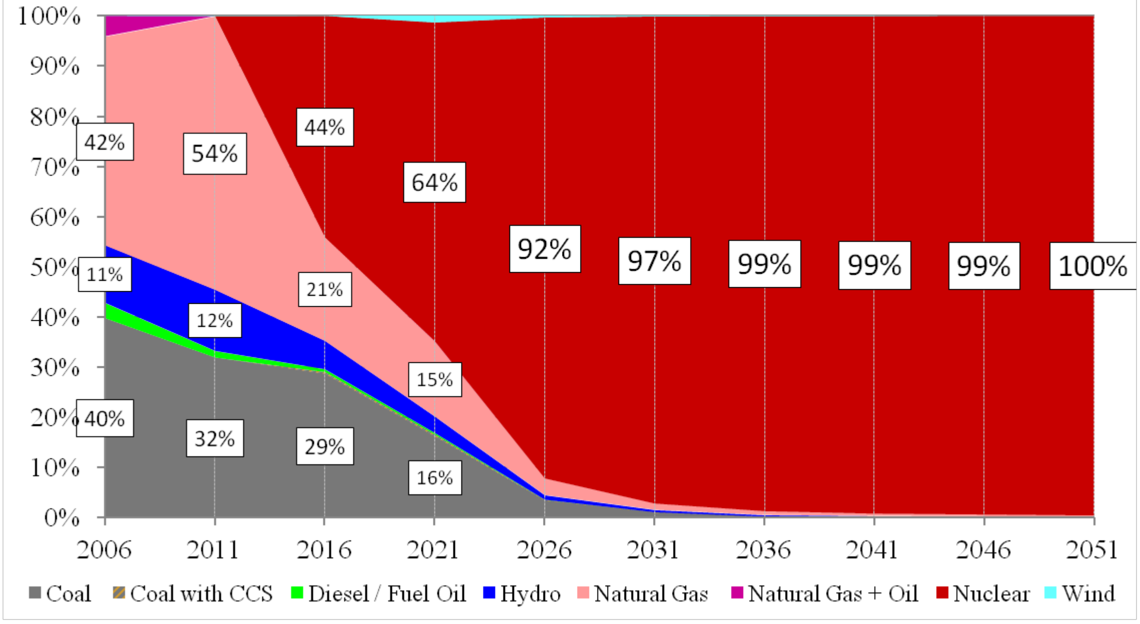

Figure 5.78. Breakdown of the primary energy resource consumed in electricity generation in the 40 TL tax per ton of CO_2, fast nuclear, fast CCS case

5.4.4.2. The 40 TL Tax per ton of CO_2, Fast Nuclear, Slow CCS Scenario.

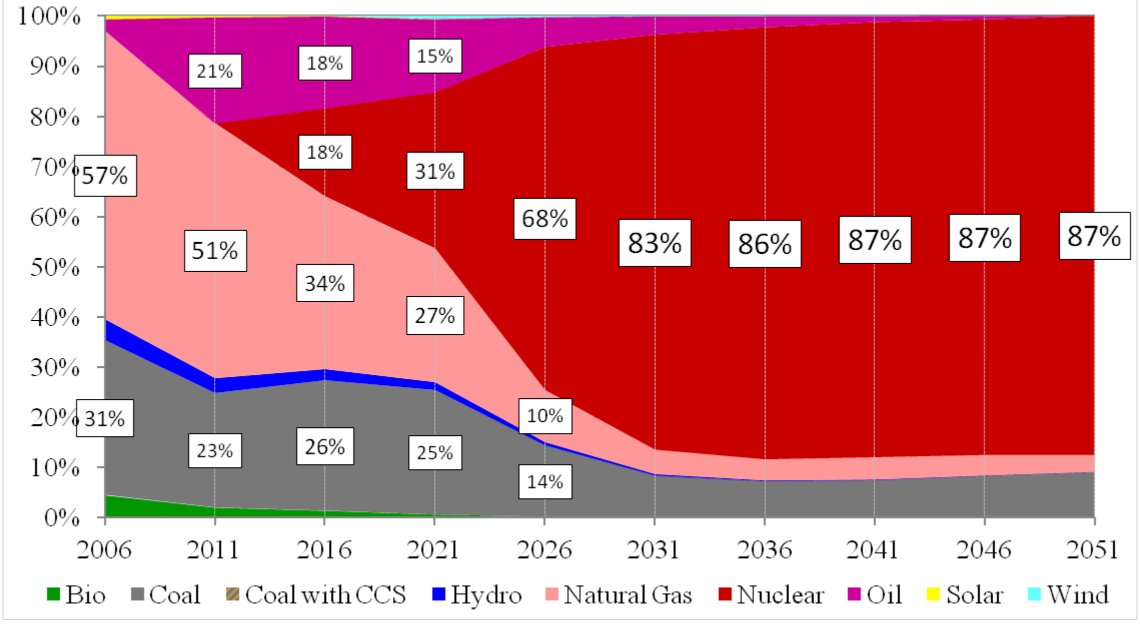

Figure 5.79. Breakdown of the primary energy resource consumption in the 40 TL tax per ton of CO_2, fast nuclear, slow CCS case

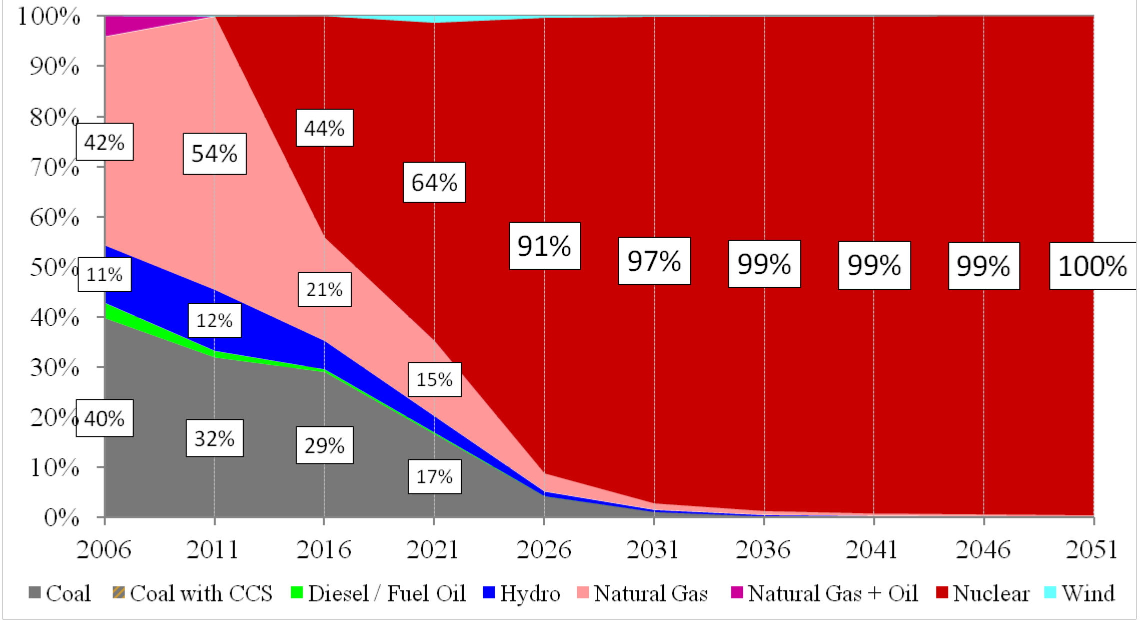

Figure 5.80. Breakdown of the primary energy resource consumed in electricity generation in the 40 TL tax per ton of CO_2, fast nuclear, slow CCS case

5.4.4.3. The 40 TL Tax per ton of CO_2, Slow Nuclear, Fast CCS Scenario.

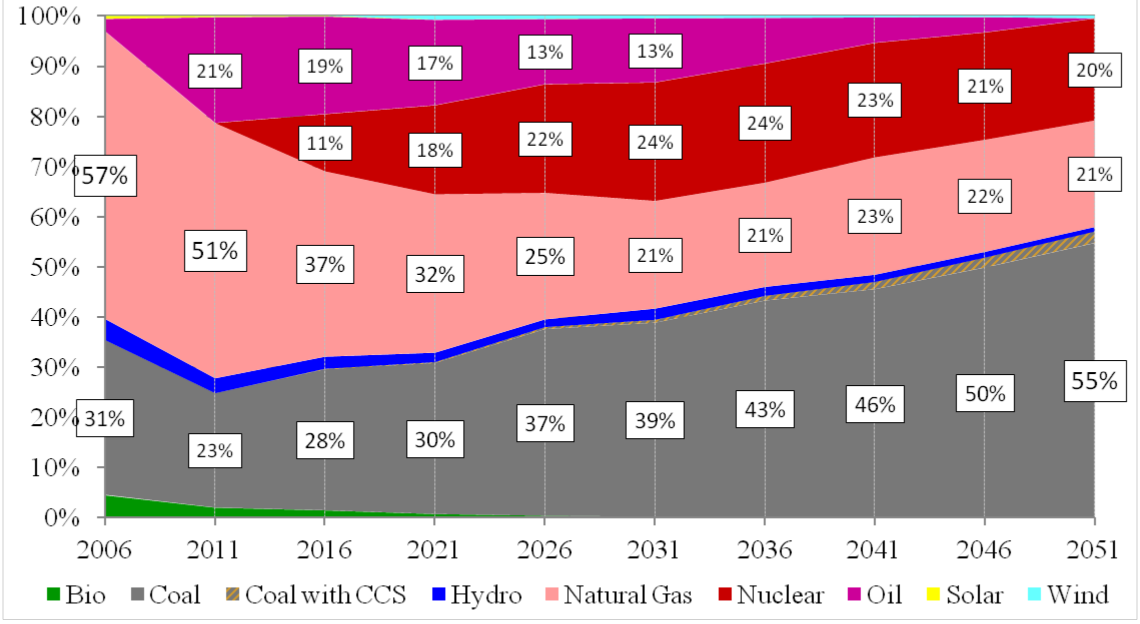

Figure 5.81. Breakdown of the primary energy resource consumption in the 40 TL tax per ton of CO_2, slow nuclear, fast CCS case

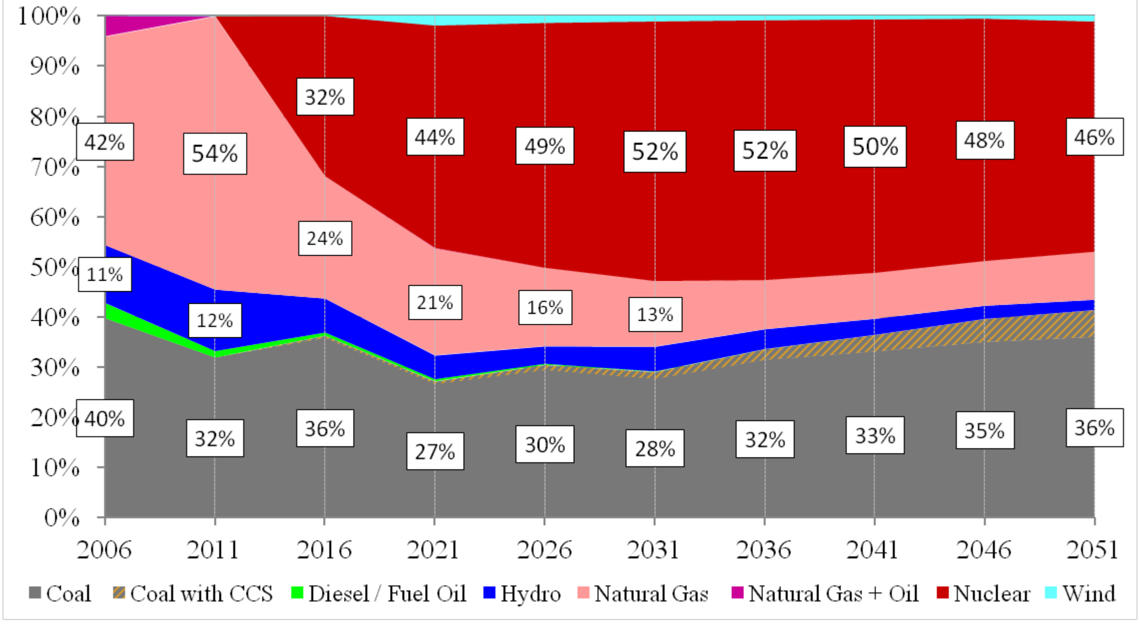

Figure 5.82. Breakdown of the primary energy resource consumed in electricity generation in the 40 TL tax per ton of CO_2, slow nuclear, fast CCS case

5.4.4.4. The 40 TL Tax per ton of CO_2, Slow Nuclear, Slow CCS Scenario.

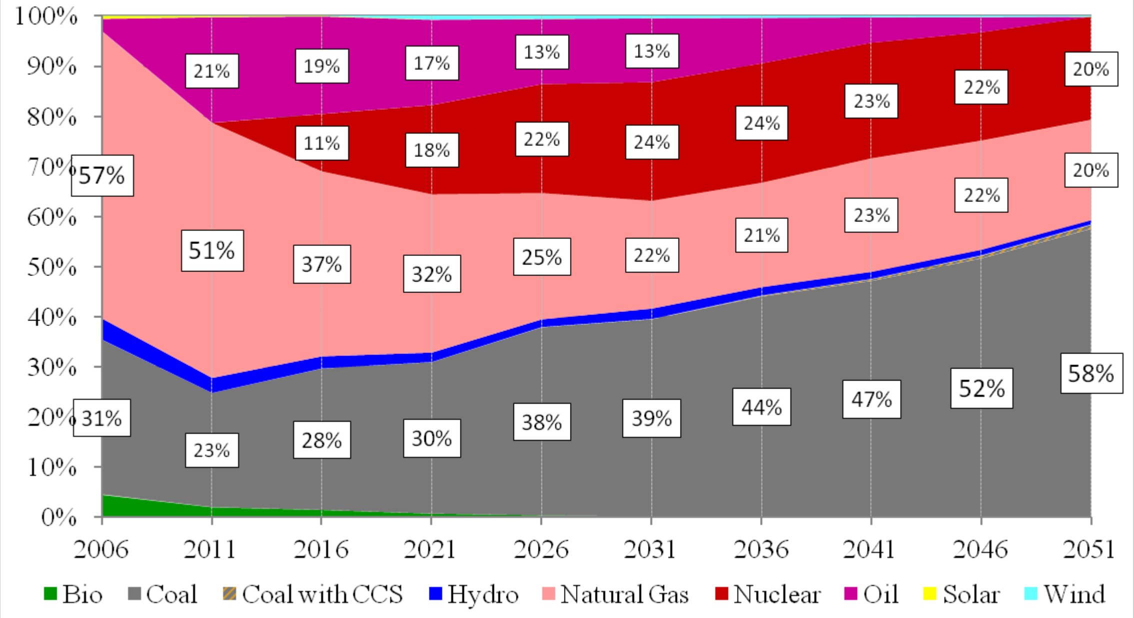

Figure 5.83. Breakdown of the primary energy resource consumption in the 40 TL tax per ton of CO_2, slow nuclear, slow CCS case

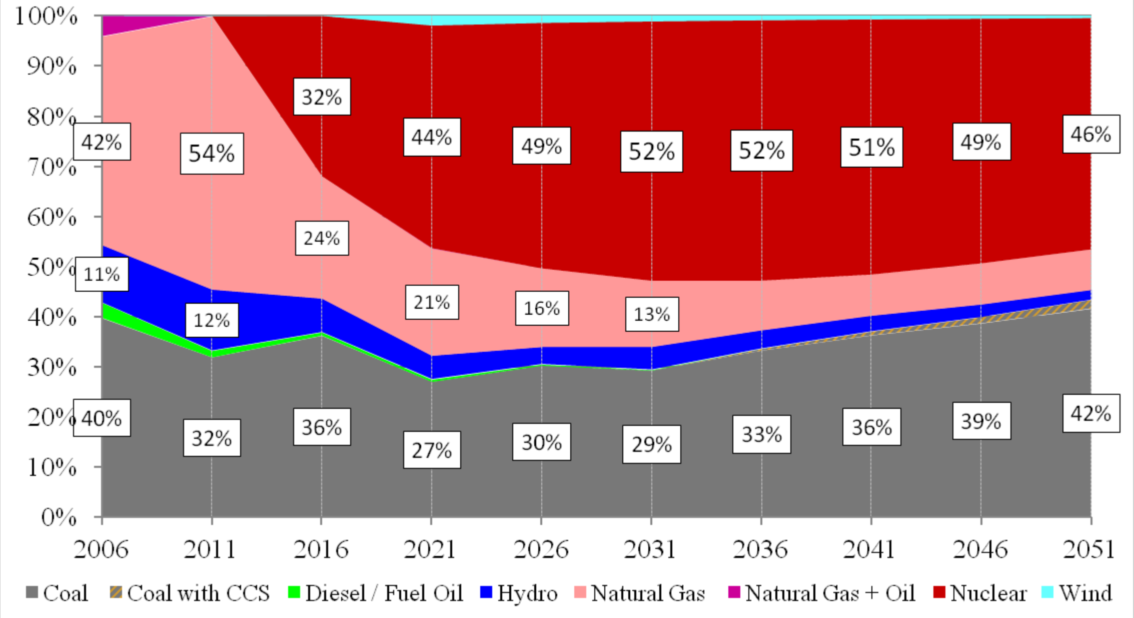

Figure 5.84. Breakdown of the primary energy resource consumed in electricity generation in the 40 TL tax per ton of CO_2, slow nuclear, slow CCS case

5.4.5. The 50 TL Tax per ton of CO_2 Emission Scenarios

The “fast nuclear, fast CCS” and “fast nuclear, slow CCS” scenarios portray identical energy resource breakdown figures (Figures 5.4.5.1, 5.4.5.1, 5.4.5.2 and 5.4.5.2). The nuclear energy consumption has a share of 48 per cent in primary energy resource consumption, as early as 2016. By 2031, the mentioned share becomes 84 per cent and maintains this level thereafter. The decline of natural gas, oil and coal consumption accompany this increase in the share of nuclear energy. In the 2006–2011 period, all of the electricity generation is through hydroelectric, natural gas and coal power plants. From 2016 onwards, nuclear energy accounts for most of the electricity generation.

In the “slow nuclear” scenarios, the nuclear energy consumption does not exceed one-fourth of the total primary energy consumption, as shown in Figures 5.4.5.3, 5.4.5.3, 5.4.5.4 and 5.4.5.4. The share of coal consumption increases linearly through the period 2021–2051, reaching 54 per cent by 2051. Still, at 50 TL tax per ton of CO_2 emissions, the CCS technology is installed only to satisfy the defined lower bound constraint and the share of CCS-supported coal consumption does not exceed 10 per cent even by 2051, in the “slow nuclear, fast CCS” scenario. The share of natural gas consumption as a primary energy resource manages to stay about 25 per cent in the 2026–2051 period. In 2011, before the availability of nuclear investments, 55 per cent of the electricity is generated through natural gas, while 31 per cent is generated through coal, accounting for the 86 per cent of total electricity generation together. Nuclear energy accounts for half of the primary energy resource consumed in electricity generation, in the 2026–2051 period.

5.4.5.1. The 50 TL Tax per ton of CO_2, Fast Nuclear, Fast CCS Scenario.

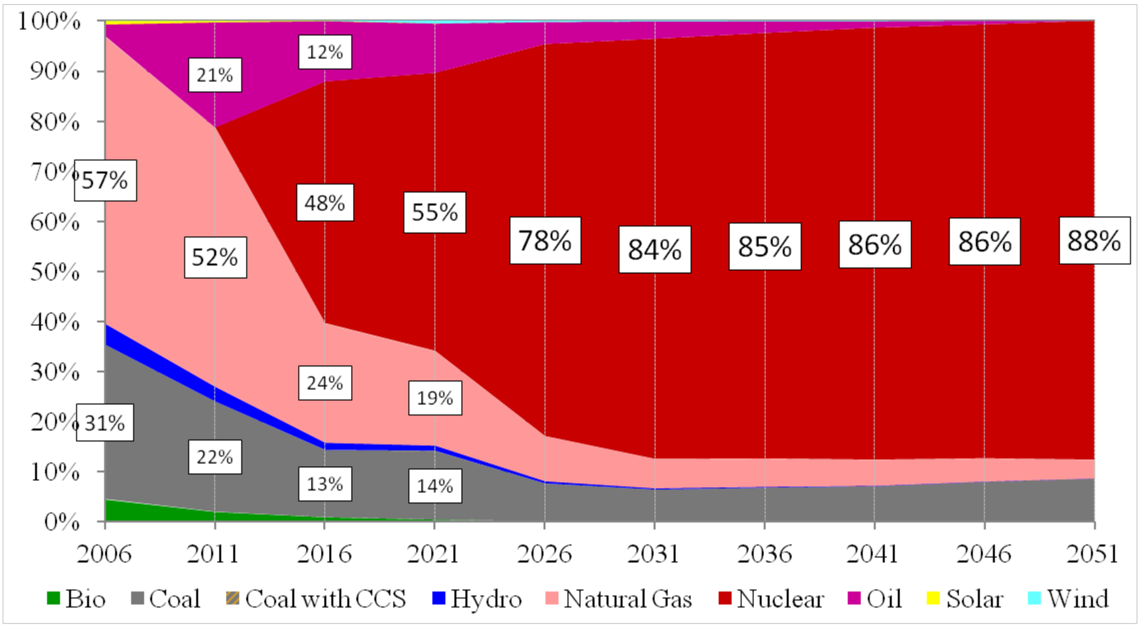

Figure 5.85. Breakdown of the primary energy resource consumption in the 50 TL tax per ton of CO_2, fast nuclear, fast CCS case

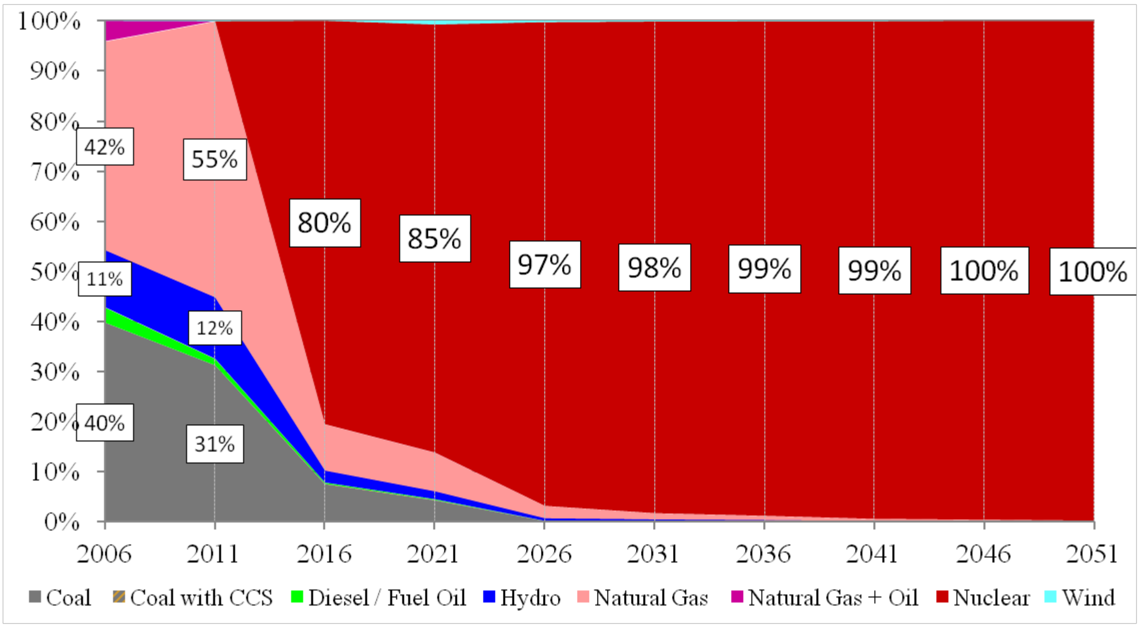

Figure 5.86. Breakdown of the primary energy resource consumed in electricity generation in the 50 TL tax per ton of CO_2, fast nuclear, fast CCS case

5.4.5.2. The 50 TL Tax per ton of CO_2, Fast Nuclear, Slow CCS Scenario.

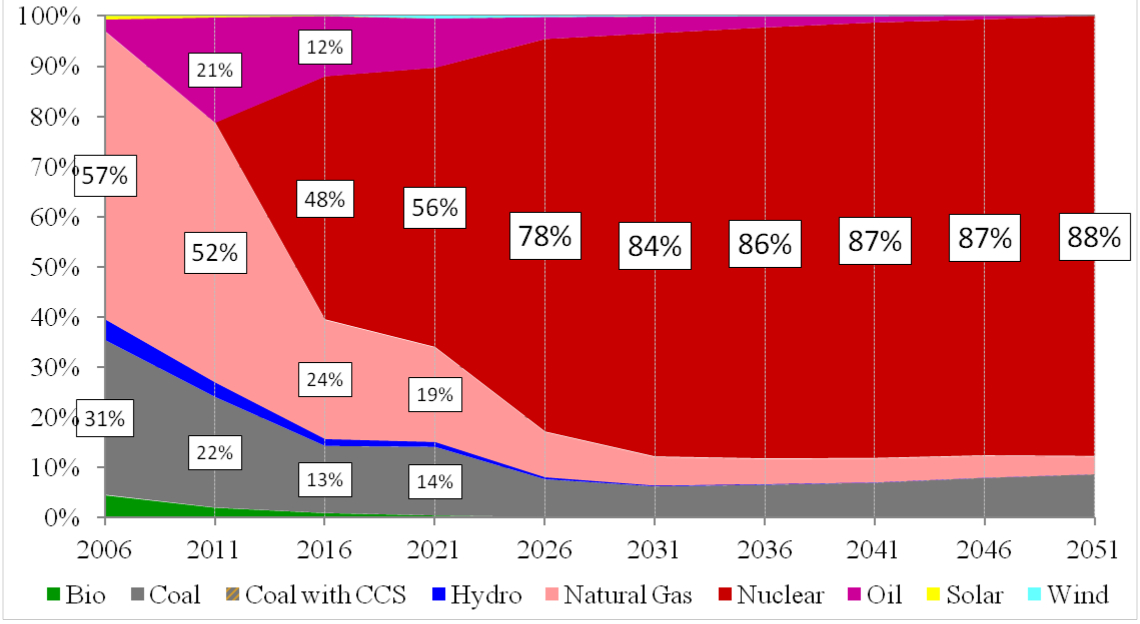

Figure 5.87. Breakdown of the primary energy resource consumption in the 50 TL tax per ton of CO_2, fast nuclear, slow CCS case

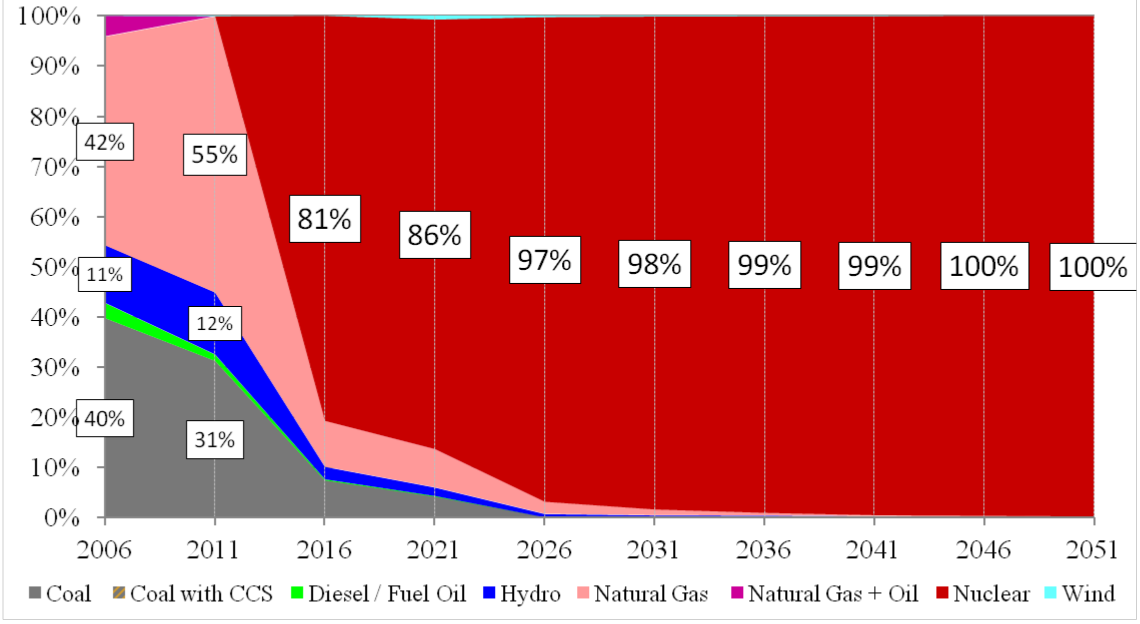

Figure 5.88. Breakdown of the primary energy resource consumed in electricity generation in the 50 TL tax per ton of CO_2, fast nuclear, slow CCS case

5.4.5.3. The 50 TL Tax per ton of CO_2, Slow Nuclear, Fast CCS Scenario.

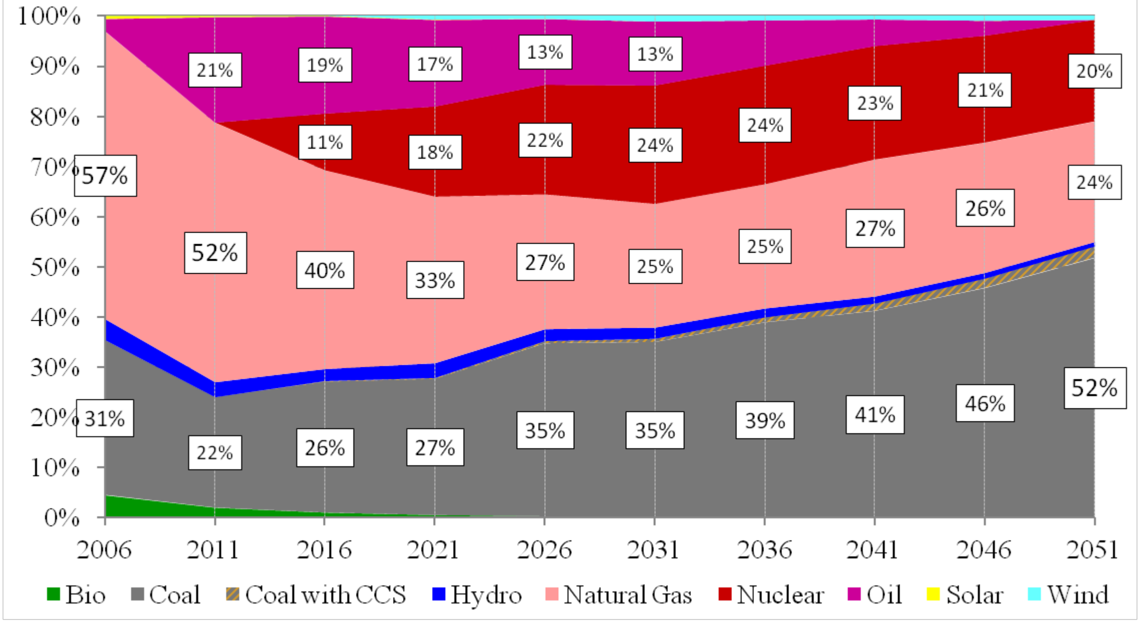

Figure 5.89. Breakdown of the primary energy resource consumption in the 50 TL tax per ton of CO_2, slow nuclear, fast CCS case

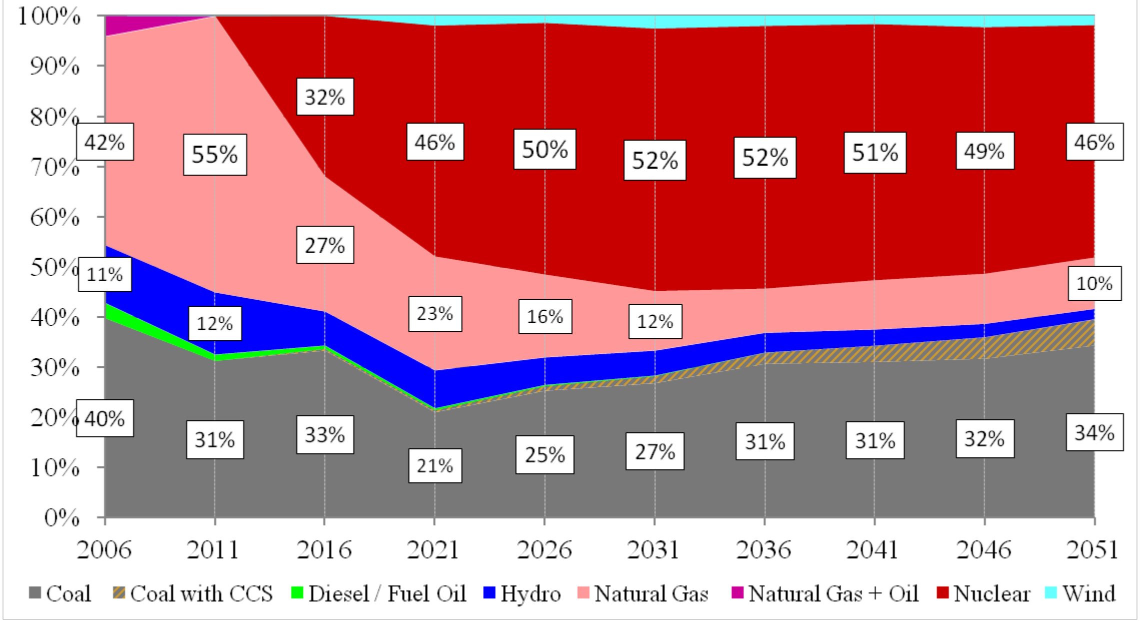

Figure 5.90. Breakdown of the primary energy resource consumed in electricity generation in the 50 TL tax per ton of CO_2, slow nuclear, fast CCS case

5.4.5.4. The 50 TL Tax per ton of CO_2, Slow Nuclear, Slow CCS Scenario.

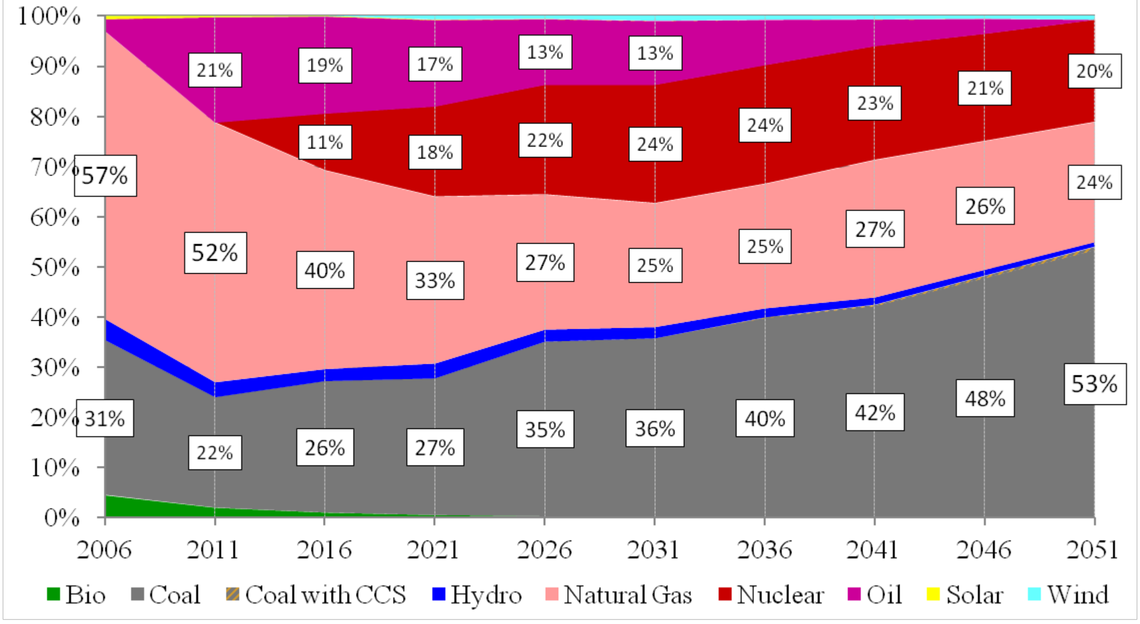

Figure 5.91. Breakdown of the primary energy resource consumption in the 50 TL tax per ton of CO_2, slow nuclear, slow CCS case

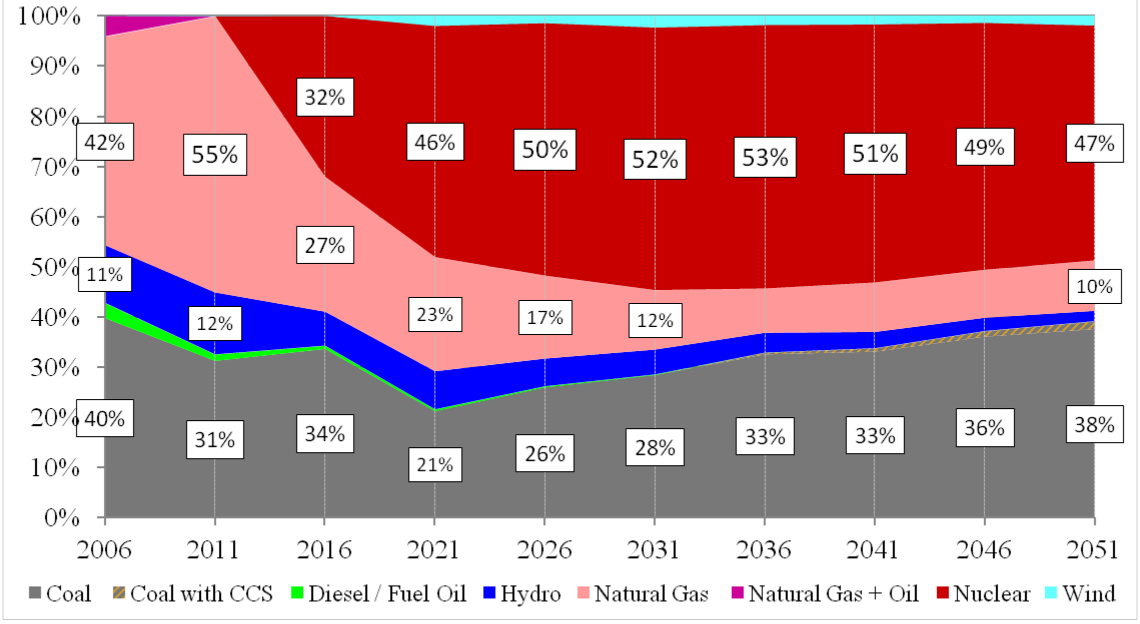

Figure 5.92. Breakdown of the primary energy resource consumed in electricity generation in the 50 TL tax per ton of CO_2, slow nuclear, slow CCS case

5.4.6. Comparison and Analysis of the Taxation Scenarios

One of the most striking aspects of the scenarios pertaining to the taxation of CO_2 emissions is the minimum use of CCS technologies in all such scenarios. Even at the highest level of tax —50 TL per ton of emitted CO_2— and limited nuclear energy investments (the slow nuclear case), paying tax (penalty) for CO_2 emissions is preferred over investing in CCS technologies. From 20 TL tax per ton of CO_2 emissions onwards, nuclear power is highly dominant in the "fast nuclear" scenarios (peaking at 87–88 per cent of primary energy use in the later stages of the planning horizon).

In the 50 TL per ton of emitted CO_2 scenario and the "slow nuclear" case, hydroelectric energy becomes significant, maintaining a share over five per cent until 2026. Then, with the introduction of CCS at its minimum level, use of hydroelectric energy slowly declines.

Similar to other scenarios, oil usage declines over time, since it is both expensive and emission-rich. Oil consumption approaches to zero by 2051. In the "high nuclear" scenarios and under high tax rates, this elimination of oil occurs as early as 2046.

Electricity generation is almost completely dependent on nuclear power in the "high nuclear" scenarios. In the "low nuclear" scenarios, coal —without CCS activity for the most part— and nuclear energy are the two major sources, while natural gas has a significant portion, too.

Table 5.3 shows the average annual cost and emissions amount associated with each tax scenario. The cost variations are not significant, at one-half of a per cent at most. As expected, increasing the tax amount yields better CO_2 emissions reduction in "fast nuclear" scenarios. In general, raising the tax beyond 30 TL per ton of emitted CO_2 has diminishing returns in terms of CO_2 emissions mitigation. As observed in the results of the scenarios constraining CO_2 emissions directly, again, the highest total system costs are in the "slow nuclear, fast CCS" scenarios. The comparison of costs and emissions amounts with the base scenario are displayed in Figure 5.4.6.

Table 5.3. Total system costs and emissions of the scenarios discouraging CO_2 emissions through taxes

Scenario	Cost (M TL/a)	CO_2 (kt/a)
TAX10_FF	73,376	226,040
TAX10_FS	73,150	231,172
TAX10_SF	73,411	241,091
TAX10_SS	73,154	249,417
TAX20_FF	73,500	186,252
TAX20_FS	73,483	192,392
TAX20_SF	73,484	231,208
TAX20_SS	73,292	233,992
TAX30_FF	73,395	176,530
TAX30_FS	73,383	176,710
TAX30_SF	73,470	224,118
TAX30_SS	73,305	226,255
TAX40_FF	73,271	171,941
TAX40_FS	73,265	172,324
TAX40_SF	73,490	213,465
TAX40_SS	73,303	216,406
TAX50_FF	73,340	163,526
TAX50_FS	73,298	163,351
TAX50_SF	73,576	206,274
TAX50_SS	73,425	208,824

Interestingly, there are breakpoints where the total system cost declines faintly, while the tax level is increased. This may be explained as follows: At first, when the tax level increases, remedies are sought through technology or process improvements or fuel switches. Because the system profits from these alterations in aggregate, an amount less than the tax is paid in average. When the tax levels are kept increasing, at some point, these alterations are not more advantageous than paying the tax and the system starts just paying tax and maintain the emissions. Thus, the incurred cost converges to the amount of tax and since tax amounts are negative costs for the system, the total system costs are now lower, in comparison to the scenario where a slightly lower amount of tax is applied. If the tax level still keeps increasing, it exceeds a certain level where it becomes more expensive than investment and operating cost of some emission reducing technologies —e.g., CCS— and the system selects to invest in these more expensive and less-polluting technologies, in order to avoid paying tax. Hence, these breakpoints can occur as long as there is superior technology available.

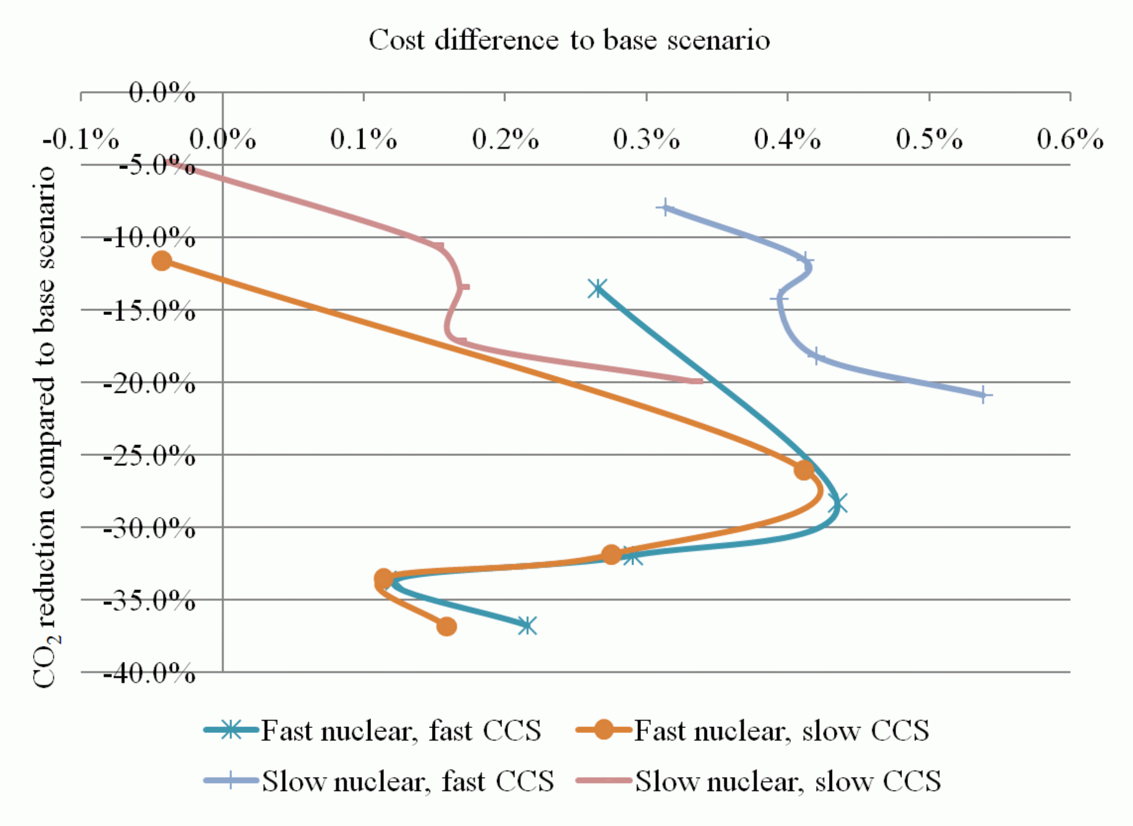

Figure 5.93. Comparison of the emission taxation scenarios with the base scenario

Note that the MARKAL model evaluates the total tax amount as a type of revenue by default. Figure 5.4.6 reflects this default approach. An alternative approach would be to think of the total tax amount as an additional burden on the system, which has to be paid on top of all resource, investment and operation & management costs. Thus, looking from this alternative point of view, total system costs are expected to increase. The outcome of this alternative approach is depicted in 5.4.6. Using this alternative approach, taxation scenarios become much more costly and less favorable than scenarios constraining CO_2 emissions directly.

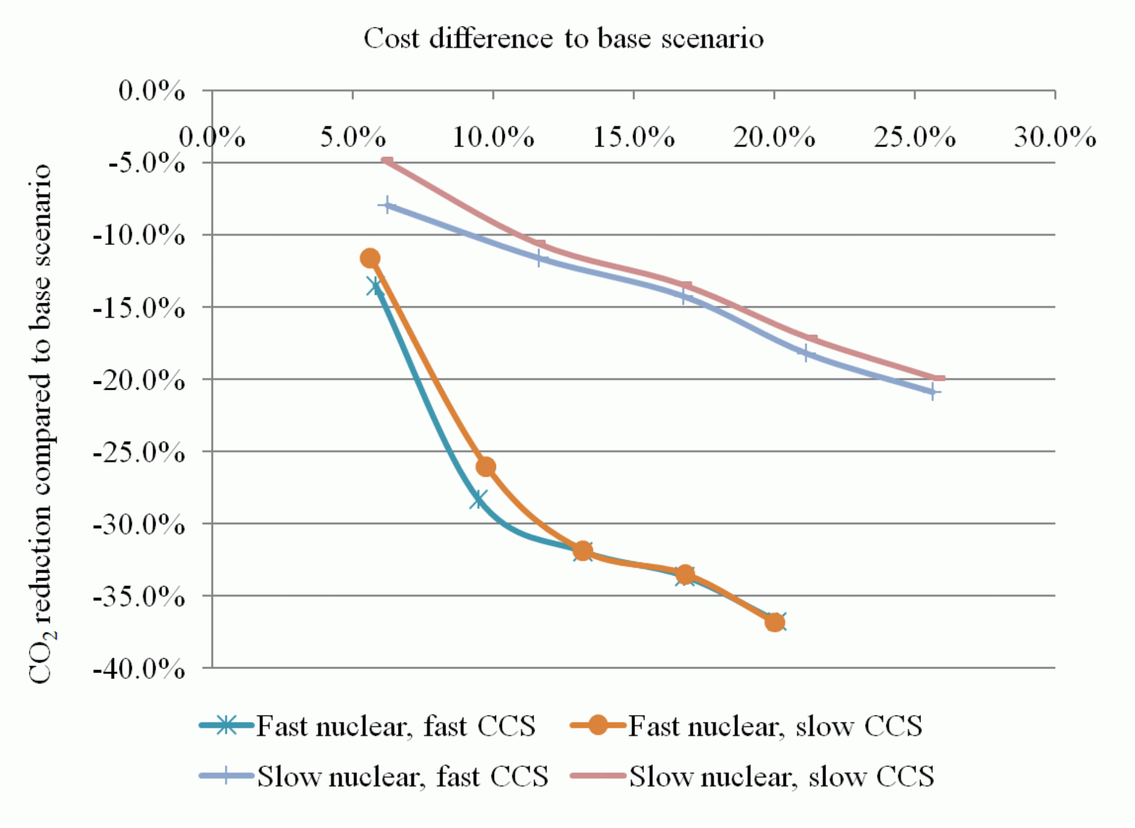

Figure 5.94. Comparison of the emission taxation scenarios with the base scenario

5.5. Scenarios Assuming High Nuclear Energy Costs

In all of the previous scenarios, the readily available nuclear energy has a unit cost between 0.409 and 0.053 U.S dollars per kWh —including raw material, investment, operation & management and waste management costs. There is a high probability that nuclear energy in Turkey may cost more in practice. The unit costs associated with nuclear energy are multiplied by three and are inspected for the cases of 30 per cent emissions reduction and 30 TL taxation per ton of CO_2 emission. The nuclear power and CCS technology are in their “fast” states in both cases. There is no need to examine the “slow CCS” case, since the CCS technology investments barely fulfill the lower bound constraint (as depicted in Figures 5.5.1 and 5.5.2).

As portrayed in Figures 5.5.1 and 5.5.2, both in the 30 per cent emissions reduction scenario and 30 TL per ton of CO_2 taxation scenarios, nuclear energy does not exceed 30 per cent of primary energy consumption. As one might expect, in comparison to the originally assumed costs of nuclear energy, nuclear power use is very low. Nuclear energy maintains its share of 30 per cent in primary energy consumption throughout the period 2021–2051 in the 30 per cent emissions reduction scenario. In the 30 TL per ton of CO_2 taxation scenario, the share of nuclear energy in primary energy consumption decreases to below 10 per cent by 2051.

In the 30 per cent emissions reduction case, total system costs of high nuclear energy costs scenario is 2.2 per cent more than that of “fast nuclear, fast CCS” scenario. In the 30 TL per ton of CO_2 taxation case, total system costs of high nuclear energy costs scenario is 0.6 per cent more that of “fast nuclear, fast CCS” scenario. In both cases, there is no significant change in CO_2 emissions, when compared to the “fast nuclear, fast CCS” versions with originally assumed nuclear energy costs.

5.5.1. The 30 Per Cent Reduction, High Nuclear Energy Costs Scenario

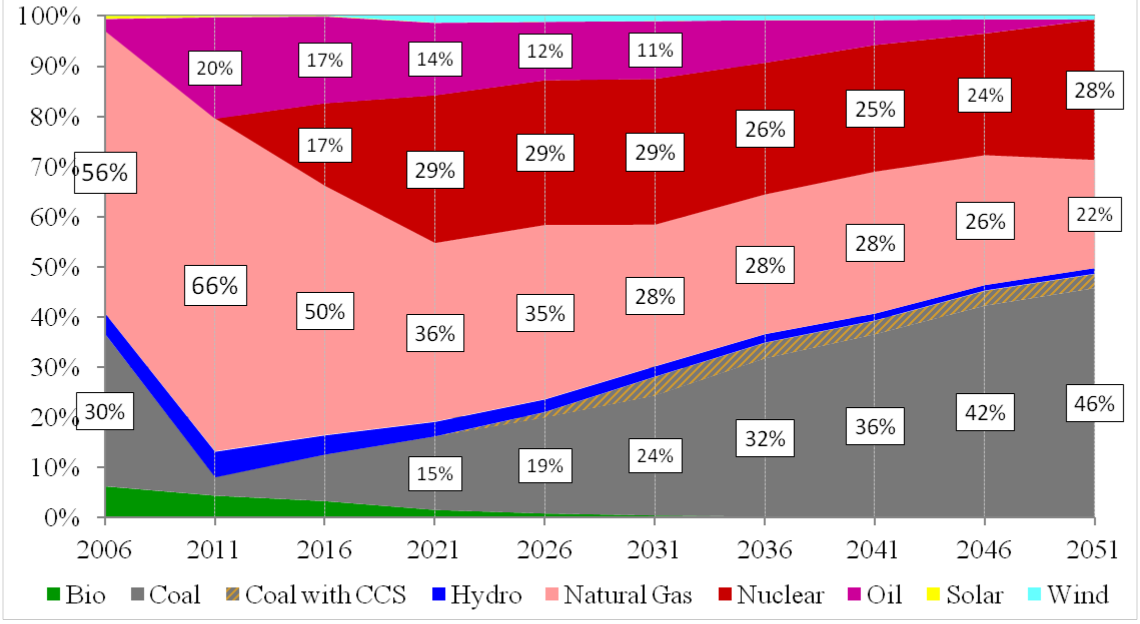

Figure 5.95. Breakdown of the primary energy resource consumption in the 30 per cent reduction, high nuclear energy costs case

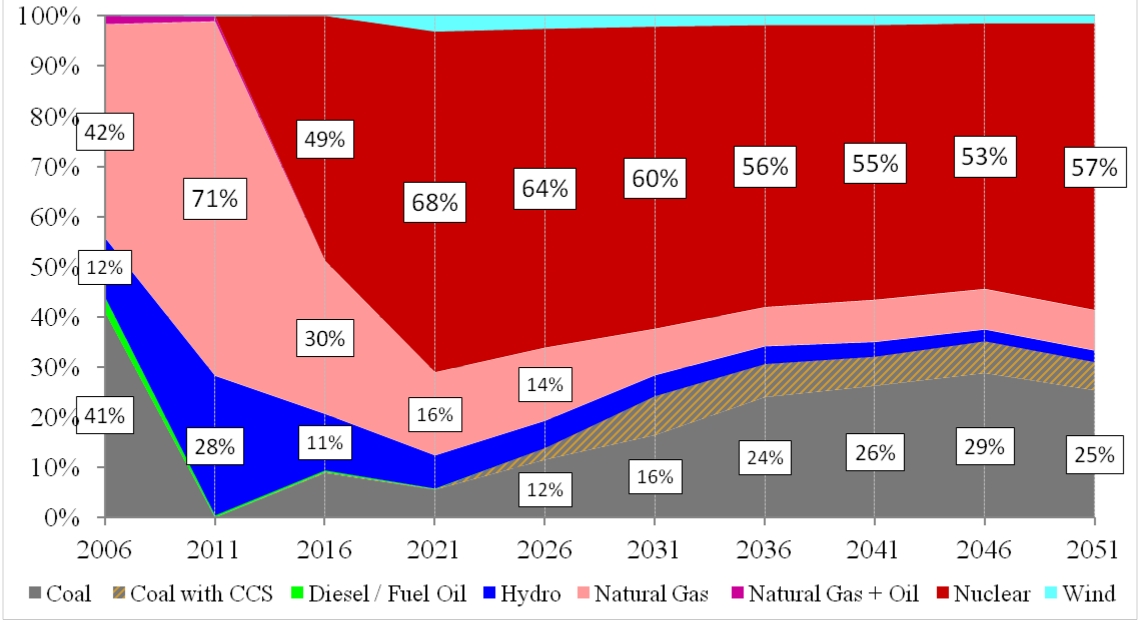

Figure 5.96. Breakdown of the primary energy resource consumed in electricity generation in the 30 per cent reduction, high nuclear energy costs case

5.5.2. The 30 TL Tax per ton of CO_2, High Nuclear Energy Costs Scenario

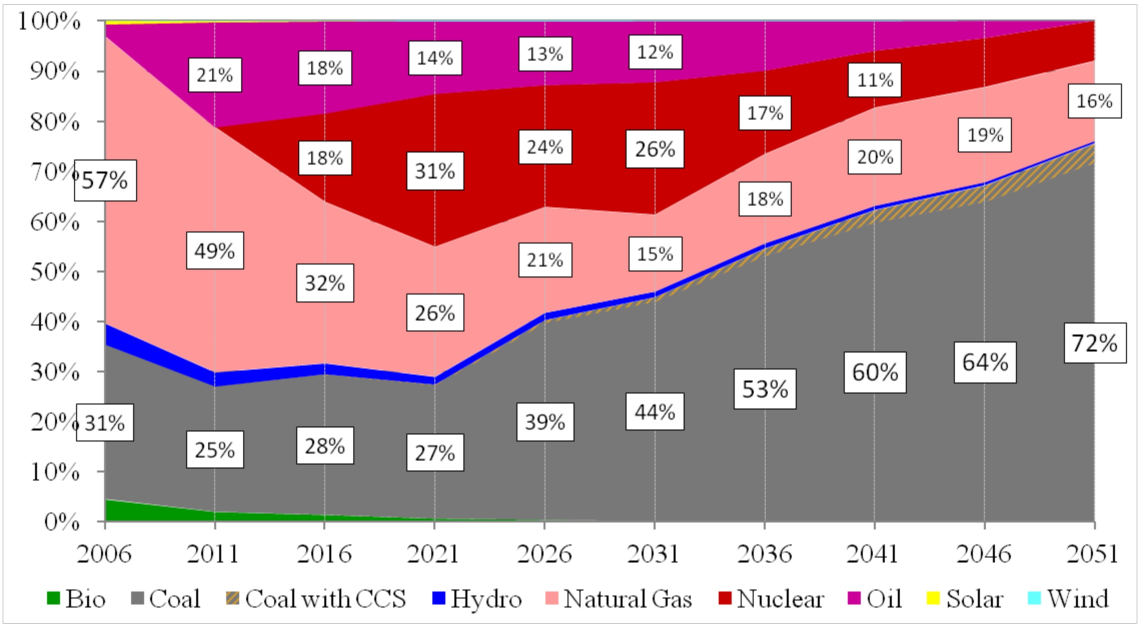

Figure 5.97. Breakdown of the primary energy resource consumption in the 30 TL tax per ton of CO_2, high nuclear energy costs case

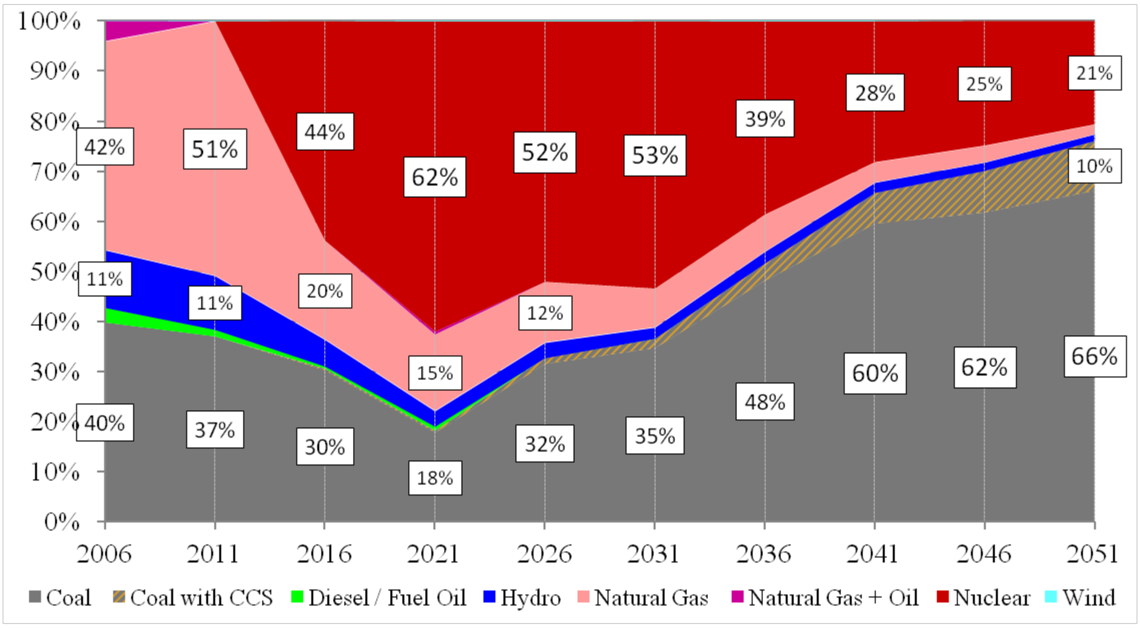

Figure 5.98. Breakdown of the primary energy resource consumed in electricity generation in the 30 TL tax per ton of CO_2, high nuclear energy costs case

5.6. Choosing the Best Scenario

Letting aside the ease of implementation issues regarding the emission restriction and tax application scenarios, the best scenario to be employed should both meet the aim of carbon dioxide mitigation and maintain total system cost at a reasonable level. To be able to compare different policies, a common parameter should be defined. The cost paid per ton of CO_2 reduction, in comparison to the base scenario appears to be a satisfactory performance indicator. The top ten scenarios —excluding scenarios in the base family— with highest score (minimal cost per ton of reduced carbon dioxide) are displayed in Table 5.4.

Table 5.4. Top 10 scenarios with minimal unit CO_2 emissions reduction cost

Scenario	Cost diff. (%)	CO_2 diff. (%)	Reduction cost (TL/kg CO_2)
TAX10_SS	-0.04	-5.0	-7.8453
TAX10_FS	-0.04	-11.9	-3.6159
TAX40_FS	0.1	-34.3	3.3173
TAX40_FF	0.1	-34.5	3.5419
TAX50_FS	0.2	-37.8	4.2032
TAX50_FF	0.2	-37.7	5.7238
GEN10_FS	0.1	-10.0	6.2439
TAX30_FS	0.3	-32.7	8.4233
TAX30_FF	0.3	-32.7	8.8738
TAX40_SS	0.2	-17.5	9.4420

Depending on the percentage the CO_2 emissions desired to be reduced, an appropriate scenario may be selected among those displayed in Table 5.4. Taxation scenarios seem to provide better unit carbon dioxide reduction costs, in general. Both the TAX10_FS and TAX10_SS scenarios, which even provide a minuscule cost reduction in addition to the carbon reduction, top the list. According to these scenarios, as expected, with the deployment of nuclear technology the carbon emissions mitigation is higher, at about 12 per cent. However, even with limited nuclear power capacity a five per cent carbon dioxide emissions reduction can be achieved, without any additional costs. Then of course, a carbon mitigation of up to 38 per cent is achievable with a cost increase of 0.2 per cent where nuclear power is used extensively. Note that 18 per cent (TAX40_SS) and 20 per cent (TAX50_SS) emissions mitigation levels are attainable with limited nuclear energy investment and at a cost increase of 0.2 and 0.3 per cent, respectively.

Lastly, note that the carbon emission amounts decrease only in relation to the base scenario. In fact, they still keep increasing throughout the planning horizon, due to the ever-growing economy (check Section 4.2 for details). CO_2 emission amounts of some scenarios in the period 2006–2051 are shown in Figure 5.6.

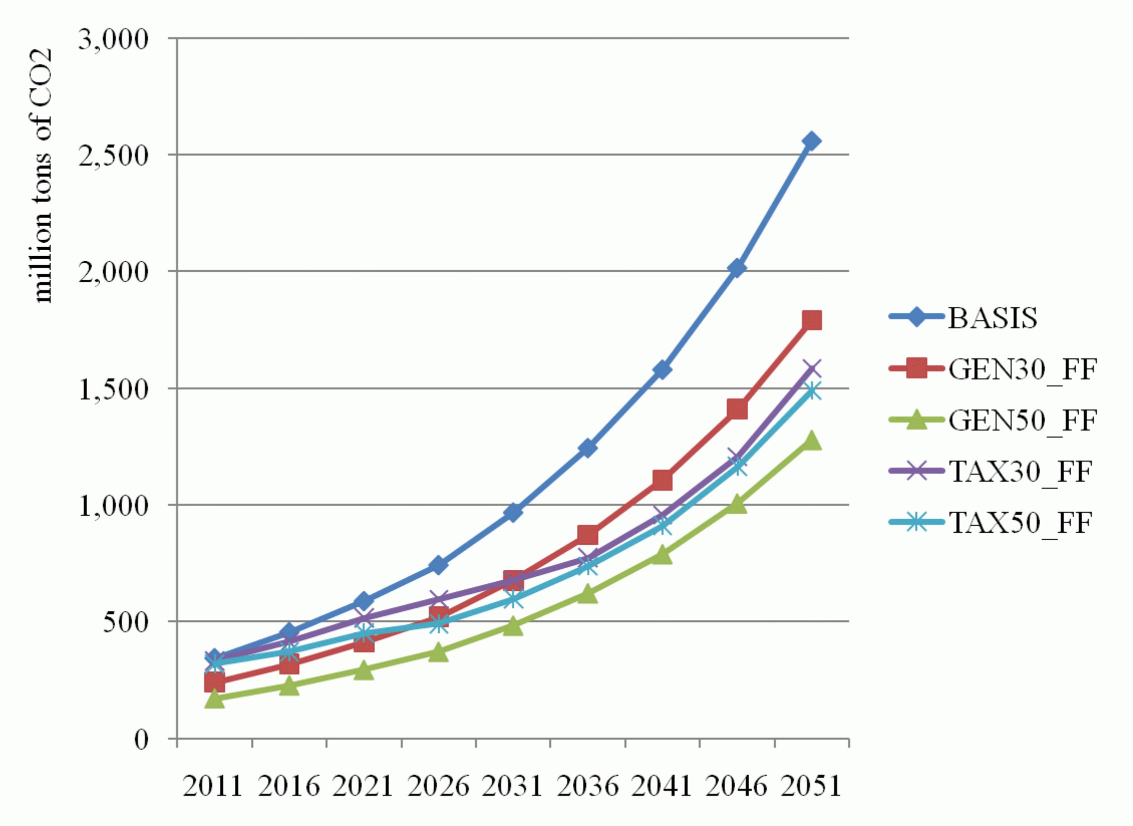

Figure 5.99. CO_2 emission results of some scenarios in the period 2006–2051

6. CONCLUSION

As discussed in the previous chapter, mitigation of CO_2 emissions up to a certain degree does not bring about high costs. This result is in parallel with the inferred results in Section 2.1. Reducing the emission beyond this degree proves costly, as outlined in the previous chapter. Moreover, as stated in the previous chapter, depending on the percentage the CO_2 emissions desired to be reduced, an appropriate scenario among the scenarios studied in Chapter 5.1 may be selected. Scenarios discourageing CO_2 emissions through taxes seem to provide better unit carbon dioxide reduction costs in comparison to the scenarios constraining CO_2 emission directly, in general.

Hence, compliance with the Kyoto Protocol and even the interim CO_2 emission reduction targets of the European Union —outlined in the introductory chapter— should not be too difficult for Turkey, given the availability of nuclear power in 2021.

Elaboration of the industrial sector, as discussed in Chapter 4 allowed us to work more precisely, increasing the significance of the findings in the last chapter. The existence of a large generic "Other Industrial Demand" subsector hurt the bottom-up approach of the model by empowering a large generic demand similar to the one in macro-economic energy-environment-economy models. Through this work, this generic demand and its respective generic technologies are refined and detailed very significantly, but the generic subsector still has a major presence (48 per cent of the total industrial energy demand).

Frankly, the model requires continuous improvement and update of data, like every other major model in an ever-changing sector like the energy sector. A logical extension to this research would be application of other scenarios, which may possibly include sector-specific scenarios. But the design of such scenarios requires extensive information about regional and sectoral energy strategies and therefore, the formation of these scenarios would require cooperation with the responsible government agencies.

Other than that, application of the MARKAL-ETL extension in the MARKAL family of models to the model at hand would be an interesting research extension. Thus, endogenous technological learning could be investigated which would open up new possibilities, in terms of technology investments.

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