Impact of European Emissions Trading System (EU-ETS) on Carbon Emissions and Investment Decisions in the Power Sector

by

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Submitted to the Engineering Systems Division
and the Department of Civil and Environmental Engineering
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Abstract:

This masters thesis assesses the impact of a emissions trading on short-term carbon abatement and investment decisions in the power sector.

Environmental benefits from carbon abatement due to emissions trading are quantified using top-down trend analysis and a bottom-up power sector model "E-simulate" to define upper and lower boundaries on carbon abatement in Germany in the first phase of the EU Emissions Trading Scheme (2005-2007).

The long-term economic and investment implications of emissions trading form the centerpiece of the thesis. A sample coal and gas investment project is modeled using discounted cash flows and analyzed using probabilistic Monte Carlo methods. The model results help explain the empirical evidence of an increase in coal investments in Germany against a preference for gas in the wider European market. The model is used to separately discuss both the price and allocation effects of emissions trading on investment decisions in the power sector. The modeling provides evidence of the dominance of fuel prices on the long-term investment decision and highlights under which carbon and fuel price scenarios the current preference for coal over gas investments could be reversed. Model results show a good match when compared to power spreads which are created using empirical data. Furthermore, related policy domains such as the Clean Development Mechanism (CDM) and Renewable energy policy are assessed and sector-wide carbon abatement estimates are reconciled between fuel switching and emissions displacement from renewables.

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Phantasie ist wichtiger als Wissen, denn Wissen ist begrenzt.
A. Einstein

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1. Introduction

1.1. Motivation

In the spring of 2009, the world finds itself in several states of distress with a highly uncertain outlook on the future. In the US, the Obama Administration has made climate change one of the key policy priorities; yet the outlook on carbon markets and even the regulatory authority between EPA and Congress remains unclear. The EU with a significant carbon market is firmly committed to post-2012 carbon markets regardless of whether or not an international consensus is reached. This continuing regulatory uncertainty for the power sector comes at a time in which the world finds itself in the midst of the largest recession since the Great Depression; the global financial crisis has all but closed the credit markets, freezing large debt-financed infrastructure investments. In the US and Europe, gigantic government subsidy programs promise rapid aid for "shovel-ready" projects, with the very first grants, loan subsidies and tax incentives being rolled out while government agencies are sill increasing staff levels and write grant proposals.

At the same time, governments and utilities must look beyond the near-term demand contraction and plan the investments required to support the long-term energy demand growth. This also includes making significant investments in more flexible power grids and providing incentives for the development of a lower carbon intensive power sector. Yet, while environmental economics could suggest that carbon regulation would end the use of coal, exactly this fuel is chosen for large parts of the future grid mix. This thesis will analyze the carbon price effects on long-term investments in the power sector. The analysis will distinguish between price effects and allocation effects using various quantitative methods to analyze empirical and market data from the European Union's Emissions Trading Scheme (EU-ETS).

1.2. Background on Emissions Markets

The fundamental justification for emissions trading markets results from the desire of regulators to price environmental externalities. Emissions trading caps the total carbon output, thus providing certainty over output; trading between participants is allowed so that largest amount of abatement can occur at the lowest marginal cost. Although Europe has taken the lead on carbon markets, first environmental markets were envisioned in the United States in the 1970s but only implemented at full-scale in the early 1990s. The economist Pigou (1932) first suggested internalizing environmental costs through a tax; then Ronald Coase (1960) challenged the polluter pays principle and proved efficient outcomes could be achieved independently of initial allocation. Dales (1968) continued with this notion and strengthened the concept of transferable property rights for public goods, which was contrary to command and control regulations of the time. The US Clean Air Act first allowed companies to offset higher emissions through emission reduction credits, reducing implementation by up to 90%, compared to traditional command and control regulation, and providing an economic incentive to invest in technologies of lower carbon intensity (Tietenberg 1985). Following the success of this environmental market mechanism, it was continually applied in the US for a reduction in lead gasoline in the 1980s, as well as the sulphur dioxide emissions in coal power that formed part of the 1990 Clean Air Act (Ellerman 2003).

On an international level, emissions trading was implemented in the 1997 Kyoto Protocol which is now regarded as a central pillar of global climate policy. Since its ratification in 2005, it has served as the central international climate change regulatory framework and as the basis for the global carbon market. It sets legally binding targets for the reduction by 2012 of the six main greenhouse gases (GHGs) below 1990 levels on all Annex 1 countries which have ratified the treaty. Developing countries have no binding carbon emission reduction targets, but play a central role in the Kyoto Protocol.

Under the Treaty, three 'flexible mechanisms' were established which aim at helping achieve the emission reduction targets at least cost:

- Joint Implementation (JI): Investment among Annex 1 countries to generate Emission Reduction Units (ERUs);

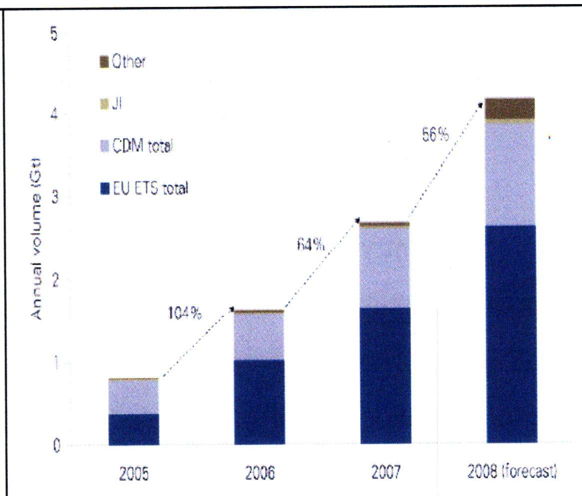
- Clean Development Mechanism (CDM): Investment in an emission reduction project in a non-Annex 1 country to generate Certified Emission Reductions (CERs), which can be sold globally.
- Emissions Trading: An Annex 1 country can sell its emission rights granted under the Treaty – Assigned Amount Units (AAUs) to another Annex 1 country.

Emissions reductions can be achieved within industrialized countries or be bought from carbon emissions offsetting projects in the developing world, which contributes to the reduction of carbon dioxide globally. The third flexible mechanism, emissions trading, served as the inspiration for the European Emissions Trading Scheme (EU-ETS) which has been implemented into EU law through the Emissions Trading Directive (European Commission 2003). The Clean Development Mechanism and Joint Implementation will be briefly discussed in Chapter 8, as these credits serve as an alternative to domestic abatement that will be described in Chapter 2.

Recently, several other compliance and voluntary carbon markets have been developed, such as the Chicago Climate Exchange or the Australian scheme in New South Wales. The total global carbon market in 2008 recorded revenues of over 125 billion dollars, the exact split between markets will be published by the World Bank in May 2009 in their annual publication "States and Trends of the Carbon Market". The table below depicts the historic development of the market, showing the rapid growth both in value and total transaction volumes.

Table 1.1: Global carbon markets volume and value

	2006		2007	
	Volume (MtCO2e)	Value (MUS$)	Volume (MtCO2e)	Value (MUS$)
Allowances				
EU ETS	1,104	24,436	2,061	50,097
New South Wales	20	225	25	224
Chicago Climate Exchange	10	38	23	72
Sub total	**1,134**	**24,699**	**2,109**	**50,394**
Project-based transactions				
Primary CDM (Clean Development Mechanism)	537	5,804	551	7,426
Secondary CDM	25	445	240	5,451
JI (Joint Implementation)	16	141	41	499
Other Compliance and Voluntary Transactions	33	146	42	265
Sub total	**611**	**6,536**	**874**	**13,641**
TOTAL	**1,745**	**31,235**	**2,983**	**64,035**



Source: Kapoor, Ambrosi (2008) and Point Carbon (2008)

1.3. The EU-ETS and the Power Sector

The EU ETS (European Trading Scheme), launched on January 1, 2005, is the key element of EU climate policy to comply with its Kyoto commitments. The EU ETS is currently the largest carbon market and has materially impacted the economic operations and investment decision-making process in the power sector, which is the largest single polluting sector. The research for this thesis is motivated by the large policy interest in this area and is enabled by the recent data availability and good reporting from the relatively liquid allowance markets. The cap and trade scheme covers about 11.500 energy intensive installations which account for around 44.7 percent of total emissions from the 27 states (2.2 billion tonnes). Emission 'allowances' are given to each operator, who is obliged to keep their emissions below the level permitted or they will have to buy allowances from other operators. Currently in its Phase II (2008-2012), the EU ETS establishes an annual cap at 5.8 percent below the 2005 verified emissions and a non-compliance penalty of €100 (up from €40). At the same time, it is maintaining the obligation to cover any shortfall in the period, the introduction of aviation (from 2012 onwards), and the possibility of banking (keeping credits for use in future years).

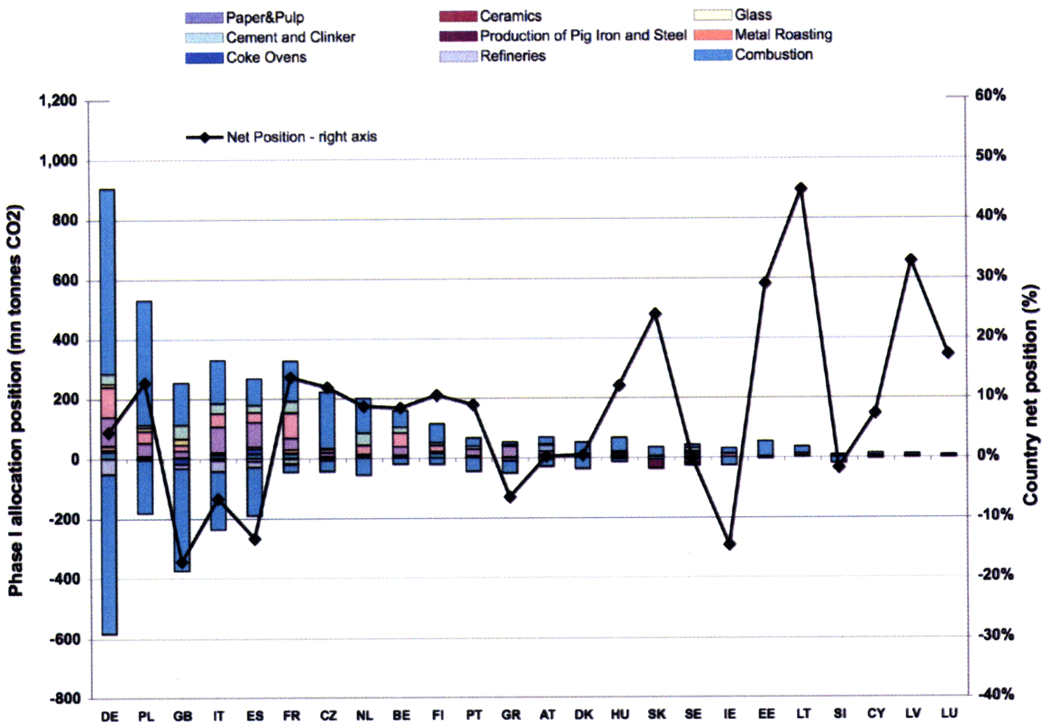


Figure 1.1 Phase I allocation by sector and country

Source: CITL Viewer

The power generation assets form part of the "combustion" installations which form the largest single sector in the EU-ETS. The chart above shows the Phase I allocations by installation and country, specifying whether the installation was over-allocated (long position above the origin) or under-allocated (short position below the origin). The data shows the large discrepancies in countries' overall positions, with the United Kingdom (GB), Spain (ES) and Italy (IT) being the economies with allocations over 250 million tons to have net short positions. The initial allocation shown for Germany was later reduced using the so-called ex-post adjustment mechanism, making Germany a net-importer of emissions credits.[1]

Emissions and Power generation in Germany

The unification of East and West Germany in 1990 started a process of industrial reorganization and consolidation of the former East Germany, which had a marked effect

[1] The European Commission contested the ex-post adjustment, yet Germany prevailed in the European Court of Justice (Weishaar, 2008).

on measured economic activity, and, more particularly, on energy use and emissions, as illustrated in Figure 1.2.

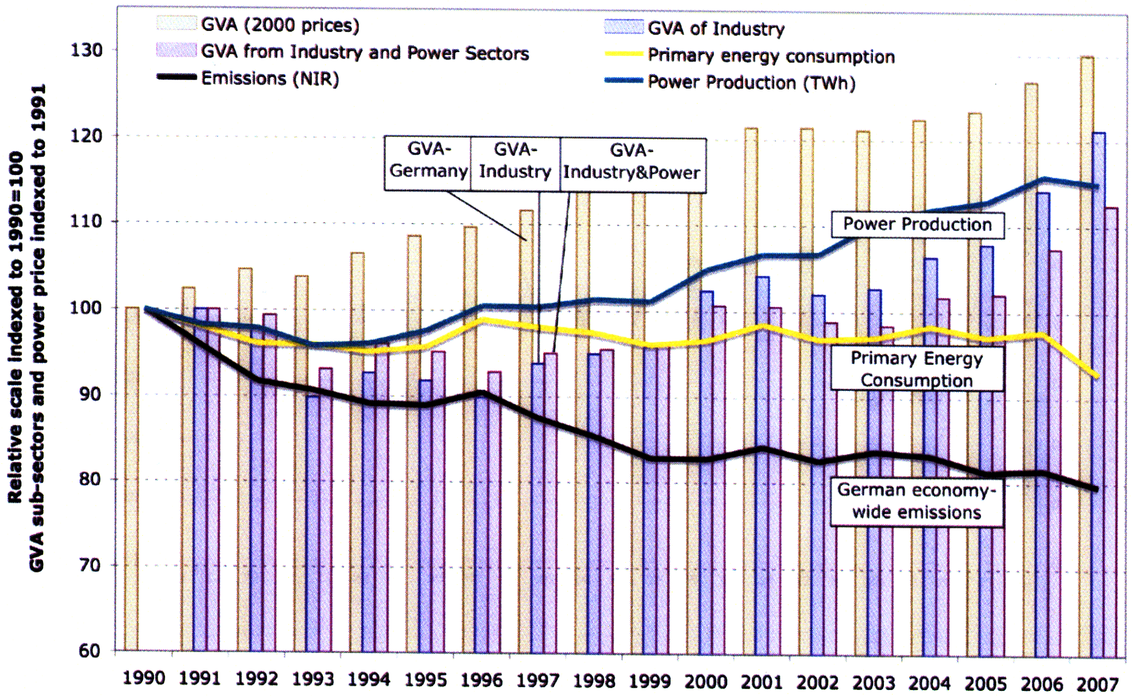


Figure 1.2: Macro-economic indicators, power prices and emissions since 1990

Source: German government, CRF reports

The chart shows that immediately following the reunification, in the years 1990-1996, German economy-wide CO_2 emissions were reduced by 10%. This coincided with a comparable reduction in industrial activity as measured by the gross value added (GVA) of the industry component of the national income statistics. 1996 marks a turning point: From then on, industrial activity rose more or less steadily, as did power production and GVA for the economy as a whole. Notably however, primary energy consumption remained flat, before a significant reduction in 2007, and economy-wide CO_2 emissions continued to decline. A particularly remarkable feature of the post-1996 period is the recovery of industrial activity, especially in the three years that marked the trial period. From 1996 through 2004, there was an annual increase of 2.1% of constant dollar GVA in the industrial sector excluding construction and power, rising to 4.4% growth between 2004 and 2007. The carbon emissions that were associated with this increase were by and large included in the EU ETS, although the sub-sectors accounting for the extra growth, like machine tools, electronics and optics, are not especially carbon intensive.

These trends are also reflected in the German power sector. In particular, fossil generation, which had fallen by 6% between 1990 and 1999, has since then risen by 12% in 2007, about half of which was lignite and the other half natural gas. In part, this trend reflects the fact that electricity use is increasing apace with GDP, but it also reflects the decline in nuclear generation. As shown in Figure 3, the level of generation from combined nuclear and fossil generation has increased only very slightly since 1999 (+2.2%). The contemporaneous increase in demand of almost 14% has been met almost entirely by renewable energy, an effect that will be further explored in Chapter 6 of the thesis. The increased fossil generation has made up for the 17% reduction in nuclear generation, which is presumably a reflection of the German government decision in 2000 to phase out nuclear power.

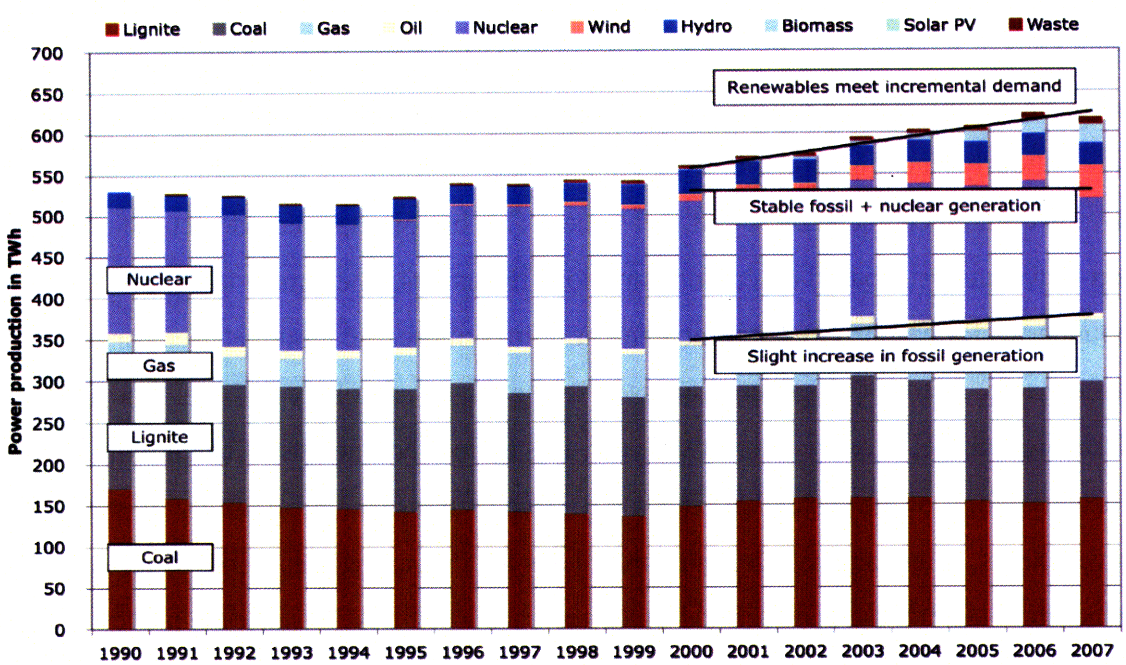


Figure 1.3: German power generation by fuel type

Source: German government, CRF reports

1.4. Approach and Methods of Analysis

Fundamentally, this thesis aims to explore the effects that carbon emissions trading and the presence of a carbon price have on long-term investment behavior in the power sector. Germany is chosen as a specific case study of analysis, given that it is the largest European economy, and has a diversified fleet of power generation technologies, and is the largest participant in the European Emissions Trading Scheme (EU-ETS). In order to accurately model the long-term effect of a carbon price on the power sector, the short-term environmental and fuel switching effects need to be understood. This is done using the bottom-up power model called "E-simulate", a cost-minimization model that simulates European electricity generation dispatch on an hourly basis over an annual cycle at the power plant level. This model is explained more fully in in Delarue, Ellerman, and D'haeseleer (2008). The entire system is organized as a set of interconnected 'zones', each of which corresponds to a specific country or group of countries, of which Germany is one. The demand for electricity is specified by zone for each hour of the year, and the model solves for the least cost dispatch of generation to meet electricity demand in all zones, given daily fuel prices. E-simulate operates as a linked hourly stacking model in which the dispatch of available generation is determined by power plant characteristics and fuel prices. This bottom-up method is combined with a top-down analysis, based on carbon emissions intensities, to estimate lower and upper boundaries for carbon emissions abatement. Furthermore, the model is used for assessing the capacity factor of all generation assets of the same technology and fuel type as well as the marginal fuel at every hour of the year. It is an indirect method of calculating the capacity factor of the system and it is a key input to assess the profitability of power investments. The marginal fuel analysis adjusts for the ramp times of the different generation technologies, as defined in the technical specifications of each power generation technology.

The main economic analysis regarding the long-term investment behavior in the power sector relies on several modeling methodologies that are combined to provide a better insight into the profitability of a marginal coal and gas investment. The model is based on a discounted cash flow model that calculates the annual cash in- and outflows from the operation of a power plant, under the technical assumptions which are taken from the previously mentioned, bottom-up "E-simulate" model. Rather than relying on a static analysis of several price scenarios, as is often done in the literature, the model uses probabilistic methods to provide a more dynamic insight into the power sector. The principal inputs into the model, gas prices, coal prices, and carbon prices, are entered as distributions which are fitted to the empirical data set. This way, the model is used to calculate returns on investment, both as a net present value calculation as well as an internal rate of return calculation to determine the more profitable investment. In addition to several model outcomes, standard sensitivity analysis is applied to all the key technical and financial inputs to quantify the impact that a change in these factors would have on the final outcomes.

Finally, the results from these model simulations are compared to empirical data of power sector spreads that are reported on power exchanges, or by financial data providers, such as Bloomberg or Reuters. Power spreads compare the power price to the input prices required to generate power and make several simplifying assumptions as to the technical details of power generation. These spreads are calculated for the earnings a utility makes for generating power one MWh from coal (called dark spread), as well as the earnings from generating one MWh using gas (called spark spread). These power market spreads can then be reduced by the carbon price given the carbon intensity of the fuel (then called "clean" dark or spark spreads). These spreads provide a daily quantification of the earnings a utility can make; subtracting the spark from the dark spread provides an insight as to whether it is more profitable to generate power from gas or from coal. Assuming that a marginal power investment is only dispatched when it is profitable to do so, these spreads implicitly express capacity factors and can thus be compared to the capacity factors that the bottom-up model calculates.

1.5. Thesis Structure

The thesis provides quantitative modeling approaches to estimate both the environmental and the economic consequences that emissions trading has on the power sector.

Chapter 2 explores these environmental effects of carbon trading by quantifying the options for carbon emissions abatement. Short-term fuel switching in the power sector is analyzed by using several top-down and bottom-up modeling techniques.

Chapter 3 provides a discussion of the empirical evidence of changing investment behavior in the EU-ETS before and during the first phase from 2005-2008. Furthermore, this chapter provides a literature review of the methods used to model long-term investment decision uncertainty.

Chapter 4 describes the power plant investment model that is the centerpiece of analysis of this thesis. The uncertainties of the input parameters, the distribution fitting process and the sampling using Monte Carlo methods are described in detail.

Chapter 5 discusses the price effects of emissions trading. Empirical data is used to calculate clean dark and spark spreads and these outcomes are compared with the results generated by the power sector models.

Chapter 6 quantifies the allocation effects that emissions trading has on the profitability of investments and technology choice. The chapter discusses the allocation mechanisms of grandfathering, benchmarking, and auctioning in more detail. It also comprises the effects that policy changes regarding new entrant and closure rules have had on the economics of power generation.

Chapter 7 discusses the broader implications of carbon trading by looking at the related policy fields of the Clean Development Mechanism and renewable energy policy. The results show a good fit between top-down estimates of the entire power industry including renewables and the sum of the two bottom-up estimates for carbon abatement in the power sector from fuel switching and carbon abatement from renewables.

The final chapter draws conclusions on the overall environmental and economic implications of this work and suggests areas for future research.

2. Measuring Short-term Abatement and Implications for Long-term Investment Decisions

While the main aim of the thesis is to explore the investment implications of a carbon price on the power sector, the long-term effects are an aggregation of short-term economic signals that induce fuel switching as a consequence of the carbon price. Hence understanding the fundamental mechanism of fuel switching is crucial for the analysis presented in chapters four and onwards. The bottom-up model presented in this chapter will be applied on the one hand to inform the assumptions for the capacity factor made in the investment model, and, on the other, to have the opportunity of cross-checking the model results with empirical data presented in later chapters.

2.1 Introducing methodology of measuring emissions intensities

More specifically, the reduction in CO_2 emissions is a consequence of switching from coal to the relatively less CO_2 intensive gas. Since reductions can be estimated only by comparison of actual emissions with what emissions would have been absent the EU ETS and the CO_2 price associated with it, analysts are forced to estimate this unobserved counterfactual. In this chapter, two different methods of quantifying the carbon emissions abatement are presented. Firstly, a top-down trend analysis, as used by Ellerman and Buchner (2008), is applied to the EU as a whole; secondly, a bottom-up approach is applied, according to Delarue et al. (2008), who already focused on the power sector using the simulation model applied to the EU as a whole.

The top-down approach is based on trends in economic activity, emissions, and emission intensities that require an analysis of these trends prior to the start of the EU ETS on January 1, 2005. Essentially, this approach assumes a continuation of these trends in the absence of a carbon price. Particular attention is given to the trends in emissions intensity for various indicators of economic activity. The economic activity and emissions can be observed ex post, but a counterfactual needs to be constructed by extrapolating business as usual carbon intensities from 2000-2004 and combining these intensities with the observed levels of economic activity from 2005 onwards. The difference between that level of emissions and what is observed with the carbon price constitutes the top-down estimate of abatement. Implicitly, this approach assumes that the surrounding factors would have stayed the same; and this is rarely the case. Accordingly, any complete analysis requires consideration of other factors affecting emissions that have changed from the pre-policy period. Examples are fuel prices and renewable energy policy, which will be addressed in Chapter 7. As will be explained, at least some of the abatement that can be inferred by this top-down approach cannot be attributed to the carbon price. Hence, this estimate forms an upper limit on abatement.

For a lower limit estimate, the methodology only focuses on the power sector, which constitutes 61% of the CO_2 emissions within the sectors included in the EU Emissions Trading Scheme in Germany. It is widely acknowledged (and implicit in the windfall profits critique) that power companies priced the value of CO_2 into their bids for supplying electricity to the grid. The additional carbon cost in the electricity supply bids would change the dispatch of power plants depending on their type and the availability of lower emitting (generally natural gas fired) plants to substitute for higher emitting (generally coal) plants at various times throughout the year. The availability of lower emitting generation for such fuel switching depended heavily on fuel prices and the load at particular hours. To make this estimate, the model simulates the operation of the German power sector as part of the European grid and resolves supply on an hour-by-hour and plant-by-plant basis. The actual demand and fuel prices, both of which are assumed to be independent of the carbon price, were included, too. The difference between simulations with and without the actual CO_2 price provides a bottom-up estimate of abatement in the German power sector. Since it is likely that other sectors reduced emissions to some extent in response to the CO_2 price, this estimate must be considered a lower bound. Also, the simulation model would not capture other effects of the carbon price, such as lower demand for electricity or improved efficiencies in power plants in response to the higher fuel/carbon price.

2.2 Top-down Estimate of Abatement

Top-down estimates of abatement, such as those first essayed for the EU ETS by Ellerman and Buchner (2007), rely upon aggregate data and comparison of trends before and after some policy measure is implemented. Typically, the analyst is looking for some break in the trend that could indicate that the policy had an effect. As an ex post exercise, the analyst also has the advantage of knowing the evolution of other factors that would cause emissions to be higher or lower, independently of the policy measure, or in this case, the price of CO_2 as expressed in European Union allowances (EUAs). Obviously, much depends on the choice of trend. The evolution of emission levels is not necessarily helpful, since it can be influenced by these other factors. Attributing the emission reduction to the policy measure would not be warranted, or at the least it would constitute an overstatement of the measure's effect. An important assumption in evaluating the effect of some policy measure is that the pre-policy trend in CO_2 intensity, and specifically of CO_2 emissions associated with various indicators of economic activity, would have continued without the policy measure. Intensity is not fixed; it will vary from year to year as a result of fluctuations in weather, energy prices, and the composition of economic activity. Nevertheless, the extrapolated values can be seen as an expectation that can be adjusted to the extent these other factors and their effect on intensity are known. The effect of the policy – in terms of carbon abatement - is measured by difference from what is observed and the counterfactual projection of the pre-policy trend into the policy period. Thus, counterfactual emissions would be the projected pre-policy intensity trend times the observed ex post indicator of economic activity. Figure 2.1 provides the basic elements of such an analysis of the effect of the EU ETS on Germany's CO_2 emissions.

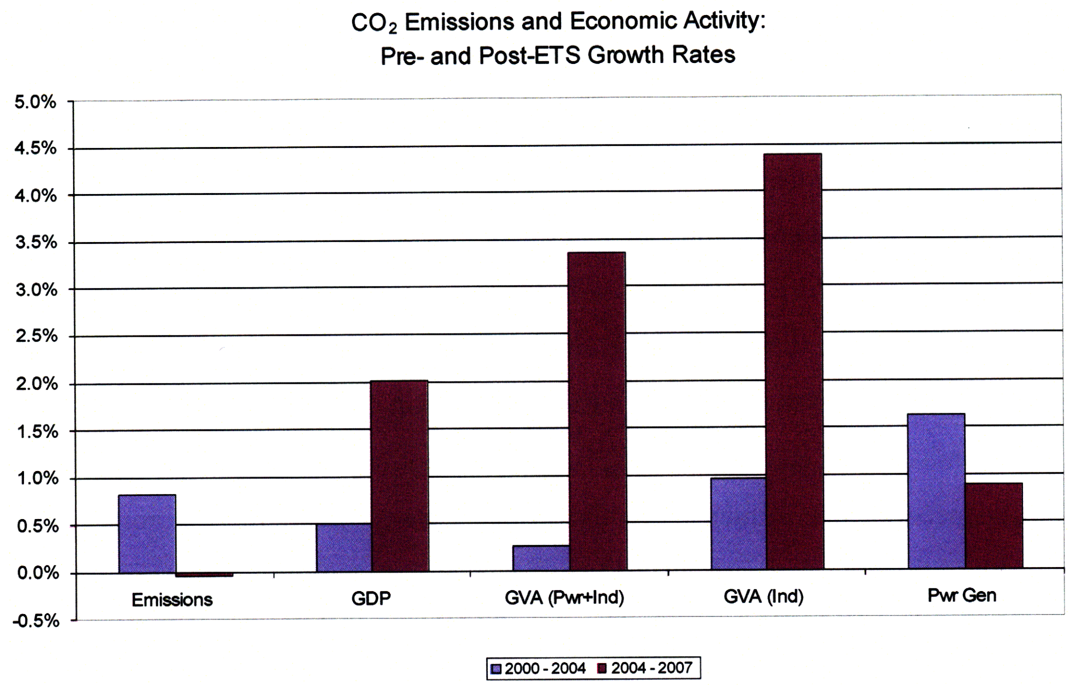


Figure 2.1: Emissions and Economic Activity Growth Rates

Source: German Government, DEHSt

The pairs of columns provide the annual rates of growth for CO_2 emissions and four indicators of economic activity for the four years preceding the introduction of the EU ETS (2000-2004) and for the three years of the trial period (2004-2007). The four indicators of economic activity are:

1. Gross domestic product (GDP), a common measure of economy-wide activity
2. Gross value added (GVA) for the sectors of the economy included in the EU ETS (mostly, electricity generation and industrial activities),
3. GVA for industrial activities alone, and power generation (which is measured in physical units instead of GVA).
4. Power generation expressed in total MWh produced

GDP is used although this indicator includes more economic activity than is encompassed by the EU ETS, but it is a readily available and commonly used indicator that is thought to have an important influence on CO_2 emissions. The GVA of the combined power and relevant industrial components of GDP comes closest to capturing the EU ETS sectors, although it would miss combustion facilities greater than 20 MW thermal that are located in sectors not included in the EU ETS. The GVA for industry alone and the generation of electricity reflect the activity levels of the two main subcomponents of EU ETS emissions. The striking feature of Figure 2.1 is the change in the growth in CO_2 emissions before and after the EU ETS in contrast to the corresponding changes for the several indicators of economic activity. In the four years prior to the introduction of the EU ETS, CO_2 emissions grew at an annual rate of about 0.8% per annum; in the three years since the introduction of a CO_2 price, emissions have declined very slightly even though economic growth was strong. Figure 2.2 shows both the evolution of observed CO_2 intensity per unit of GDP from 2000 through 2007 and also the counterfactual expected from a continuation of the 2000-2004 trend into the policy period.

The intensity observed during the policy years of 2005-2007 is not only below the trend but also below the intensity levels observed in any of the earlier years. Figure 2.3 projects ETS emissions assuming that the growth in economic activity and the trend in CO_2 intensity were the same within the ETS sectors as they were for the German economy as a whole. Actual ETS emissions are also shown and the hatched area represents the top-down estimate of abatement. The distinct flattening of emissions growth, observed in 2005-2007, may have had some other contributing factors, but it is hard to imagine that the CO_2 price did not play a role, given the general belief that economic activity and CO_2 emissions are closely linked.

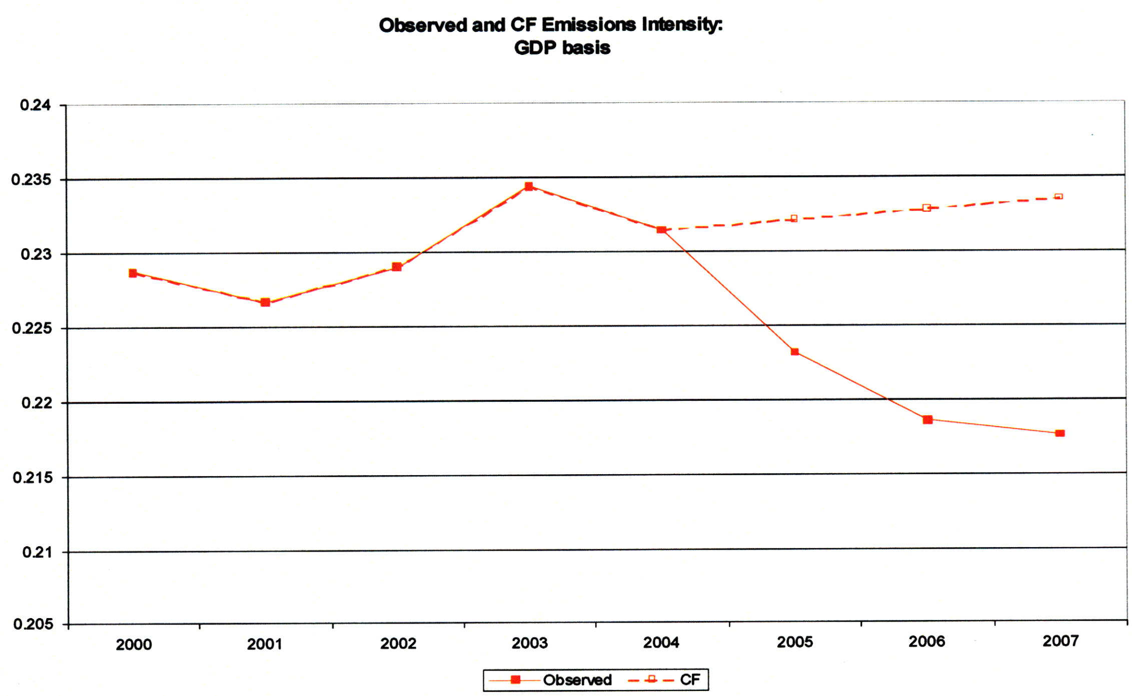


Figure 2.2: Observed and Counterfactual Emissions Intensity

Source: German government, DEHSt

The yearly pattern that is observed during these years is precisely what economic theory would predict. There was a perceptible drop in emissions as the CO_2 price was integrated into production decisions. Once that adjustment was made emissions continued to grow in some relation to GDP growth. In Germany, CO_2 emissions declined by 2.8% from 2004 to 2005 when real GDP rose by 0.8%. In subsequent years of the trial period, emissions rose by 0.8% and 2.0% while GDP rose by 2.9% and 2.5%. If the pre-policy emissions trend had prevailed, CO_2 emissions would have increased by 1.1%, 3.2%, and 2.8% in those three years, at rates that were slightly greater than the rate of GDP growth, as had been the case during the 2000-04 period.

Anyone familiar with the evolution of EUA prices over the years 2005 through 2007 will question why the abatement indicated in Figure 2.3 would be greater in 2007, when the EUA price was near zero, than in 2005 or 2006, when an average price near €20 prevailed. In response, two reasons can be adduced for placing less confidence on the annual amounts than in the estimate for the period as a whole. First, the estimates reflect a straight line projection of the pre-2005 intensity trend, as readily seen in Figure 2.2, when, in fact, the actual counterfactual intensity may have been higher or lower depending on weather and other factors. Such annual variation can be readily seen for the years 2000-2004 around a back casting of the intensity trend. Thus, in the absence of a carbon price, the counterfactual intensity could have been higher in 2005 and 2006 than shown on Figure 2.2. In fact, given the succession of two colder than normal winters, in 2004-05 and in 2005-06, and an intervening warmer than usual summer, not to mention very high natural gas prices, a higher counterfactual intensity is likely. This would imply greater abatement. Moreover, the opposite weather conditions and lower natural gas prices occurred in 2007 and could have caused the counterfactual intensity in 2007 to be lower.

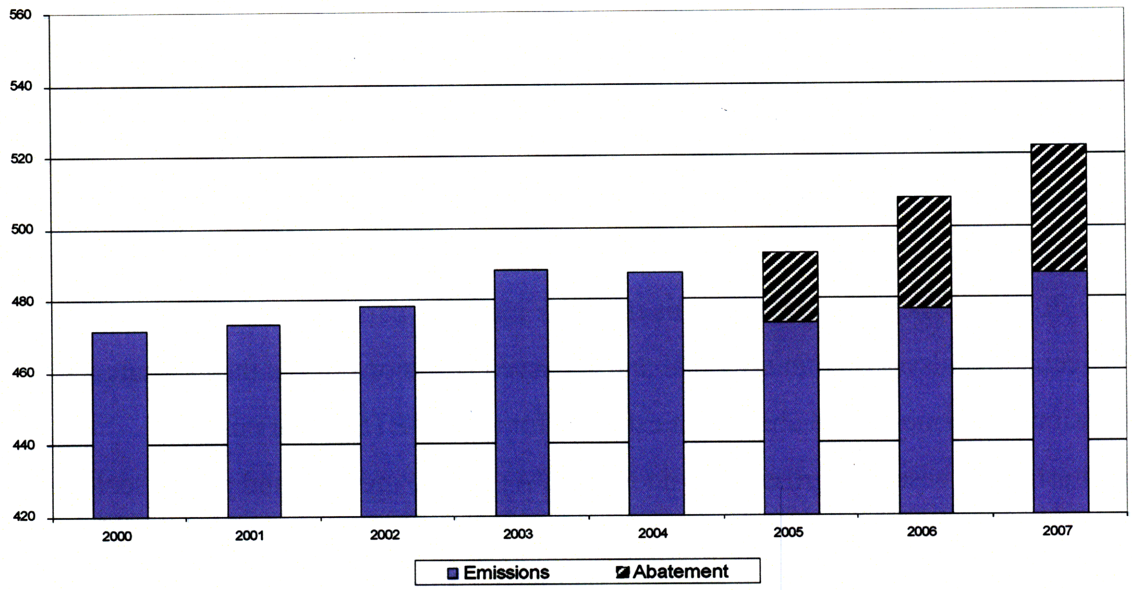


Figure 2.3: German Emissions and Estimated Abatement for all ETS sectors based on GDP CO2 intensity

Source: DEHSt

A second reason for focusing on the three years as a whole is the departure of reality from many of the assumptions common in economic reasoning. Not all investments in abatement are reversible; that emission reductions pursued during high EUA prices in 2005 and 2006 with an eye to the expected (and realized) higher 2008 CO_2 price would not be shut down or reversed when the EUA price fell temporarily to zero in 2007. Examples of irreversible and reversible abatement can be found in the power industry. Improvements in the efficiency of power generation that may have been realized in 2005 and 2006 with a view to the longer-term EUA price would not have been reversed in 2007. Similarly, contract considerations and the common lags in production decisions would be other reasons not to expect an exact correspondence between carbon prices and abatement. That being said, the more intensive utilization of gas-fired power plants at the expense of coal-fired units for supplying the spot market is readily reversible, so, consequently, a greater reliance on coal-fired generating units, and commensurately less abatement, would be expected in 2007 as the EUA price fell.

These considerations suggest that some confidence can be placed in the cumulative totals yielded by this type of top-down analysis without being overly concerned about the annual distribution of abatement. Accordingly, Table 2.1 presents four alternative estimates of CO_2 emissions abatement in Germany due to the EU ETS. The data and representative calculations made to arrive at these estimates are presented in the appendix of this paper. The counterfactuals are based on emissions intensities that are formed by dividing carbon emissions by an observed activity index (such as GDP) over the years 2000-2004 and then extrapolating this intensity into the years 2005-2007. The difference between the emissions counterfactual and observed emissions forms the estimate for emissions abatement. The abatement estimate for all EU-ETS sectors uses a counterfactual based on gross value added (GVA) for the industry and power sectors since it most closely matches the EU-ETS sectors; the calculation is also done using emissions intensities based on economy-wide GDP which is an intuitive, but less accurate measure. The power sector abatement uses counterfactuals based on power generation and GDP.

Table 2.1: Emissions Abatement Estimates

Basis of estimate (million tons)	3-yr abatement	Annual reduction
All ETS Sectors using counterfactual based on GVA Intensity	121.9	40.6 (8.1%)
All ETS Sectors using counterfactual based on GDP Intensity	85.5	28.5 (5.7%)
Power sector only using counterfactual based on generation intensity	45.7	15.2 (3.0%)
Power sector only using counterfactual based on GDP Intensity	56.7	18.9 (3.8%)

Source: Authors' calculations

These estimates vary according to the denominator that is chosen to form the intensity statistic. The important point is not the exact number but the general magnitude. The data on emissions and economic activity in Germany all point to emission reductions, coinciding with the introduction of the EU ETS and probably caused by the CO_2 price. The numbers developed here would suggest abatement of 5%, and perhaps higher, of what CO_2 emissions from EU ETS installations in Germany would reasonably otherwise have been (around 500 million tons).

There are reasons that these numbers may overstate the magnitude and for that reason they are referred to as upper-bound estimates. For instance, all energy prices rose significantly during these years independently of the CO_2 price, and these increases would have led to reductions in emissions for the same reasons that we would expect a that a CO_2 price would have been expected to have an effect. Similarly, the German government has undertaken a series of measures aimed at reducing energy use, and these probably led to energy use and emission reductions independently of the EU ETS. Still, it is doubtful that all of the indicated reduction in CO_2 emissions could be attributed to these other confounding factors. The effect of renewables in this regard will be discussed in Chapter 7.

2.3. Estimating and Illustrating Abatement in the Power Sector

Top-down approaches that depend on aggregate statistics can be supplemented by more focused analyses that concern single sectors where models and data are available. These analyses incorporate more of the sector-specific details that cannot be captured in aggregate numbers and which always raise questions about the reliance that can be placed on top-down estimates. This part of the analysis relies on a simulation model, "E-simulate," that was originally developed at the University of Leuven, Belgium and that has been subsequently calibrated to fit historical data from 2003 and 2004.[2] E-simulate is a cost minimization model that simulates European electricity generation dispatch on an hourly basis over an annual cycle at the power plant level. The entire system is organized as a set of interconnected 'zones', each of which corresponds to specific country or group of countries, of which Germany is one. Transfers of electricity can occur among zones subject to the pre-specified limits on interconnection capabilities. The demand for electricity is specified by zone for each hour of the year, and the model solves for the least cost dispatch of generation to meet electricity demand in all zones, given daily fuel prices. E-simulate operates as a linked hourly stacking model, in which the dispatch of available generation is determined by power plant characteristics and fuel prices. By adding a cost for CO_2, the stacking order is usually changed in favor of lower CO_2-emitting generation with consequent abatement for most levels of demand. The results reported below reflect the German zone only, although those results flow from running the entire model including interzonal transfers that involve Germany.

[2] More detail on the model can be found at Voorspools (2004) and Delarue, Ellerman and D'haeseleer, (2008).

As explained more fully in Delarue, Ellerman, and D'haeseleer (2008), CO_2 abatement through fuel switching depends principally on two factors: The availability of natural-gas-fired capacity and the prices of coal and natural gas. For any given stock of generating capacity, the availability of lower emitting gas-fired capacity that could be substituted for higher emitting coal-fired generation will depend upon the hourly load, which varies by daily, weekly, and seasonal cycles, and fuel prices. For instance, if natural gas prices are very low relative to those of coal, all gas generation will be committed anyway and there will be little to no capability to reduce CO_2 emissions by fuel switching. Similarly, when fuel prices favor coal-fired generation over gas-fired generation, as is usually the case, the amount of gas-fired generation available for switching will depend on the hourly load. On peak hours, when demand is high, most of the gas-fired generating capacity will be already committed, so that there will be less low-emissions capacity available for switching. The interplay of these factors and their effect on abatement is illustrated in Figure 2.4, which shows the effect of both load and fuel prices on abatement by the German power sector in response to the observed EUA price.

Due to the lack of demand data for 2007 when this analysis was performed, generation and abatement are shown only for 2005 and 2006. Load is shown by the black line at the top labeled generation (right axis in terawatt-hours/day), and it displays a decided seasonal variation reflecting the winter-peaking characteristics of German power demand. The reddish, dashed line at the bottom shows daily abatement (left axis in 000 tons/day) due to fuel switching. As can readily be seen, there is a distinct seasonal pattern to abatement. There is more in the summer, when there is less demand on the system and when more uncommitted gas-fired generation is available for switching.

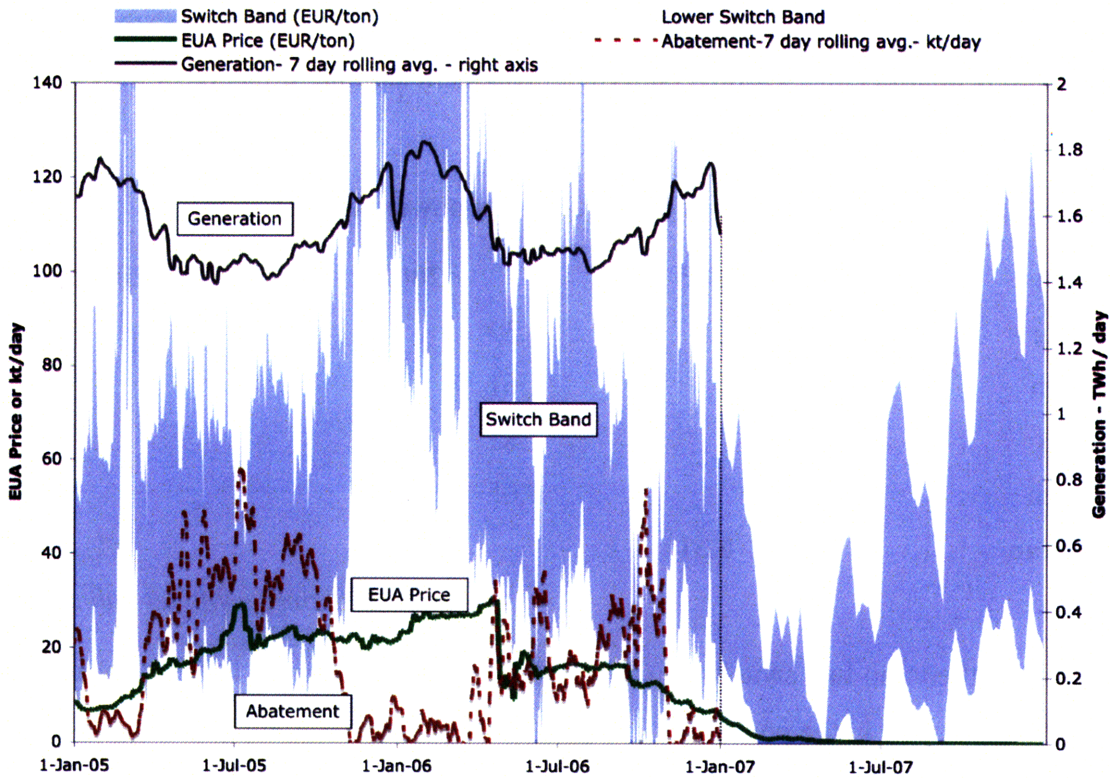


Figure 2.4: Summary of Abatement Drivers

Source: Model results, Bloomberg

The effect of the CO_2 or EUA price (green line to be read on left axis in euro per ton) also depends on fuel prices. The blue band reflects the distribution of the fuel switching points, which depend on power plant efficiencies and fuel prices. A switching range or distribution can be defined as the EUA price at which available unused gas-fired capacity would be substituted for coal-fired generation. This distribution is defined on the low side by the substitution of the most efficient and lowest cost unused gas-fired capacity for the least efficient and highest cost coal-fired capacity in service; on the high side it is defined by the substitution of the least efficient and highest cost gas-fired units for the most efficient and lowest cost coal-fired unit. Thus, the further the EUA price penetrates into this range, the greater the abatement will be, all else being equal.

This fuel price effect can be observed in comparing the abatement in the summer of 2005 with that in the summer of 2006. As shown in Figure 2.4, EUA prices were well within the fuel-switching band during the summer of 2005, in contrast to the summer of 2006 when EUA prices were frequently below the switching band. When summarized over the two years by quarters, the seasonal pattern of abatement and the influence of these other price factors can readily be seen.

Table 2.2: Estimate of abatement in the German power sector

Mn tons	**2005**	**2006**	**2007**
Jan-Mar	0.85	0.34	0.1
Apr-Jun	2.98	1.61	0
Jul-Sep	3.61	1.81	0
Oct-Dec	0.87	1.05	0
Full year	**8.31**	**4.81**	**0.1**

Source: Model calculations

Assuming little to no fuel switching in 2007, this bottom-up estimate indicates abatement of 13.2 million tons in the power sector alone for the three-year trial period, or about 1% of what emissions would have been in the ETS sectors in Germany (about 1.5 billion tons), and it can be taken as a lower bound for the reasons previously explained.

Further illustrations of power sector behavior in response to a CO_2 price

The extent and timing of fuel switching and the effect on abatement is illustrated more directly in Figure 2.5, which shows model results for 2005 alone. Abatement is driven by gas displacing coal and lignite, and the vertical lines show the percentage variations in generation from gas- and coal-fired power plants in response to actual EUA prices. Hourly abatement is shown by the black dots measured on the right axis in tons per hour. Most fuel switching and abatement occur during the summer when more unused gas-fired capacity is available. But there is also a pronounced variation within each season reflecting daily and weekly cycles in load. These are chiefly the week-day peak hours, when much of the gas-fired capacity is committed, regardless of fuel or CO_2 prices. Similarly, there are hours during the winter, when switching and abatement occurs, chiefly during the week-ends and at night when the load is relatively lower. The concentration of abatement during the summer occurs, because there are more hours with unused gas-fired capacity due to the lower load over-all during the summer months. As shown on the graph, fuel switching varies between 2% and 12% given EUA and fuel prices.

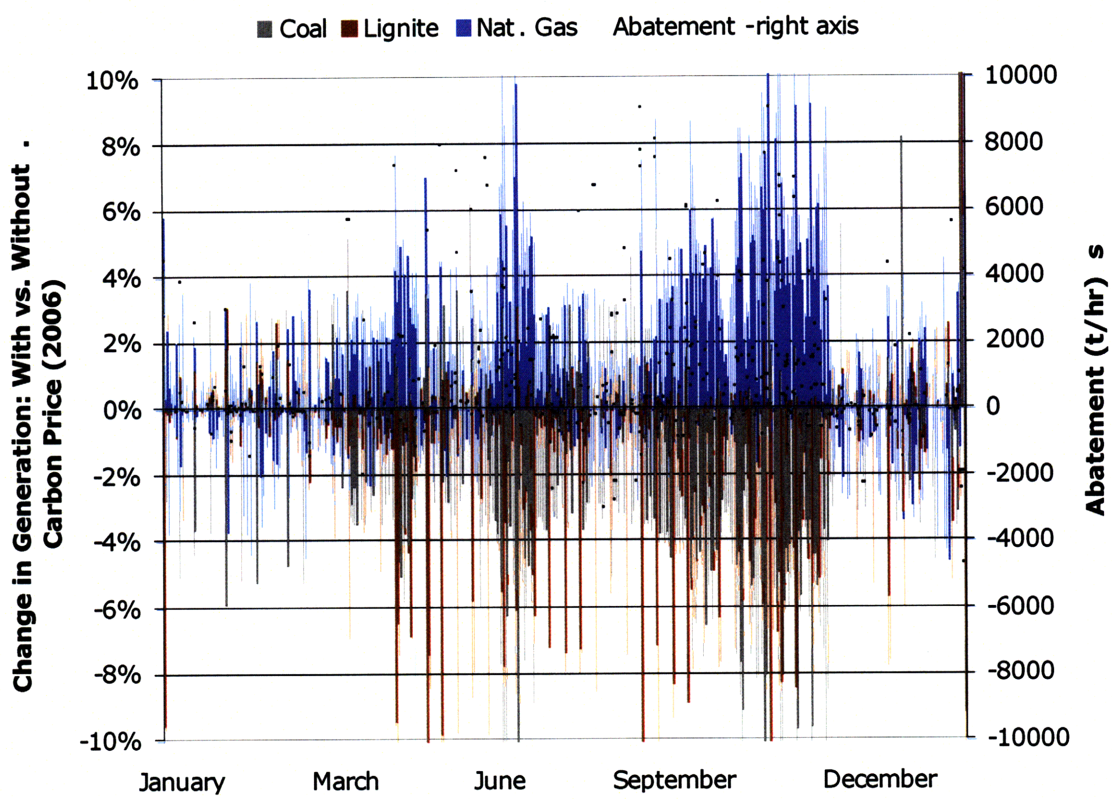


Figure 2.5: Fuel switch between gas, coal, and lignite and resulting abatement in 2006

Source: Model results

Figures 2.6 and 2.7 below provide a comparison of dispatch in the Germany electricity system in 2006, when there is no CO_2 price (2.7) and when the actual CO_2 price (2.6a) is simulated. Figure 2.6 also shows hourly abatement. There are perceptible changes, but the change is not as great as hoped or feared by various parties. With the observed CO_2 price, natural gas fired generation penetrated more deeply into the maroon, hard coal band and hard coal displaced some lignite (yellow band) mostly on week-ends during the summer, when the highest abatement tends to be observed. Lignite and hard coal still provide an important part of base-load power and natural gas and oil-fired units still provide the peaking capacity regardless of season.

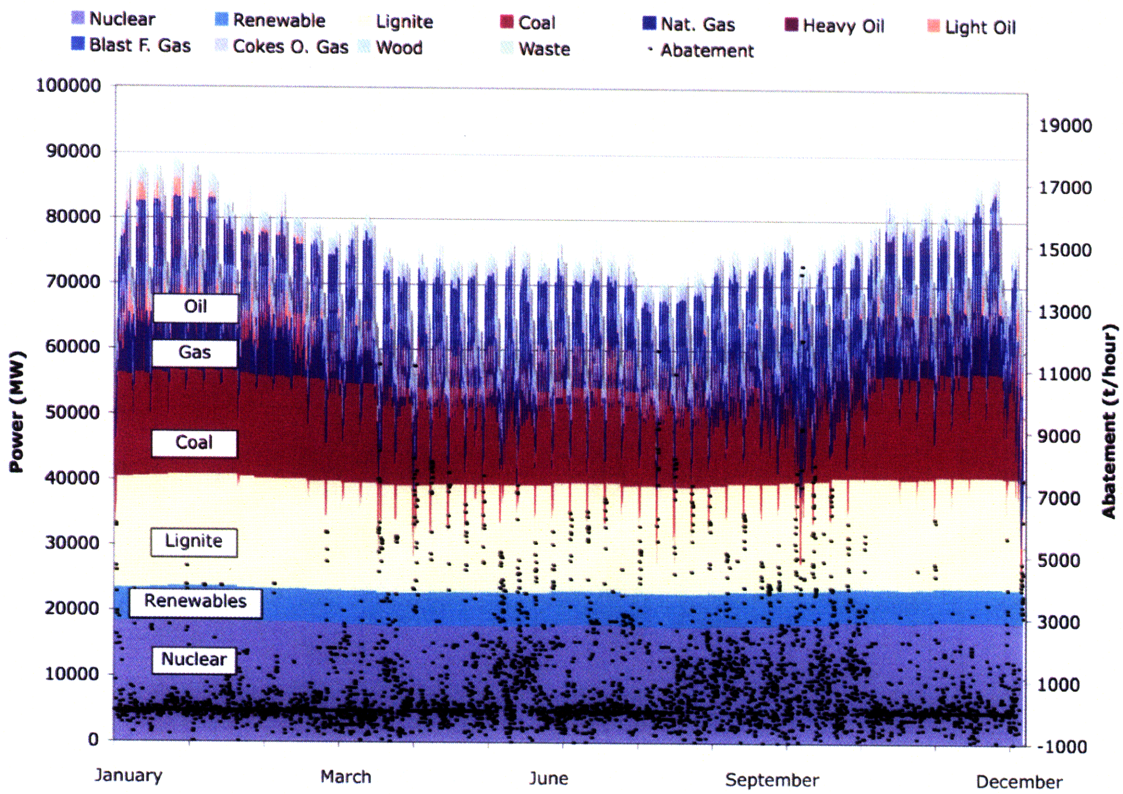


Figure 2.6:Model Results of Abatement and Load with a CO2 price

Source: Model results

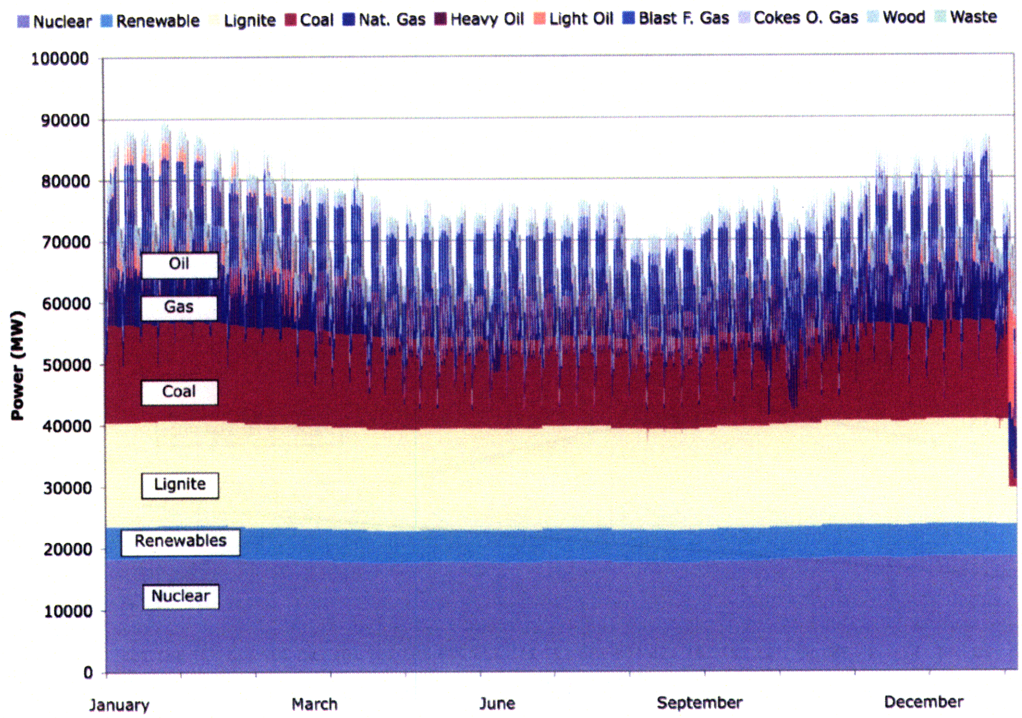


Figure 2.7: Model Results of Abatement and Load without a carbon price

Source: Model results

The influence of load, fuel and CO_2 prices on abatement in the German power sector can be summarized as in Figure 2.8 below. The figure aggregates the hourly abatement and generation data points into daily values to correspond to EUA and fuel price data. Then these daily values are ordered from highest to lowest abatement and expressed as a relative measure from 100, for the day with the greatest abatement, to 0 for the day with the least abatement. Linear trend lines are added for easier analysis. High abatement tends to coincide at low loads when the system offers the most flexibility for fuel switching, gas/coal ratios are low which results in a low switching band, as well as high EUA prices so that the EUA price is most likely to fall within the fuel switch band. As load and natural gas prices increase relative to coal; when EUA prices decline, abatement diminishes. As the slopes of the trend lines show, load has more effect than the price factors, and the gas/coal price ratio is as important as the EUA price in determining abatement.

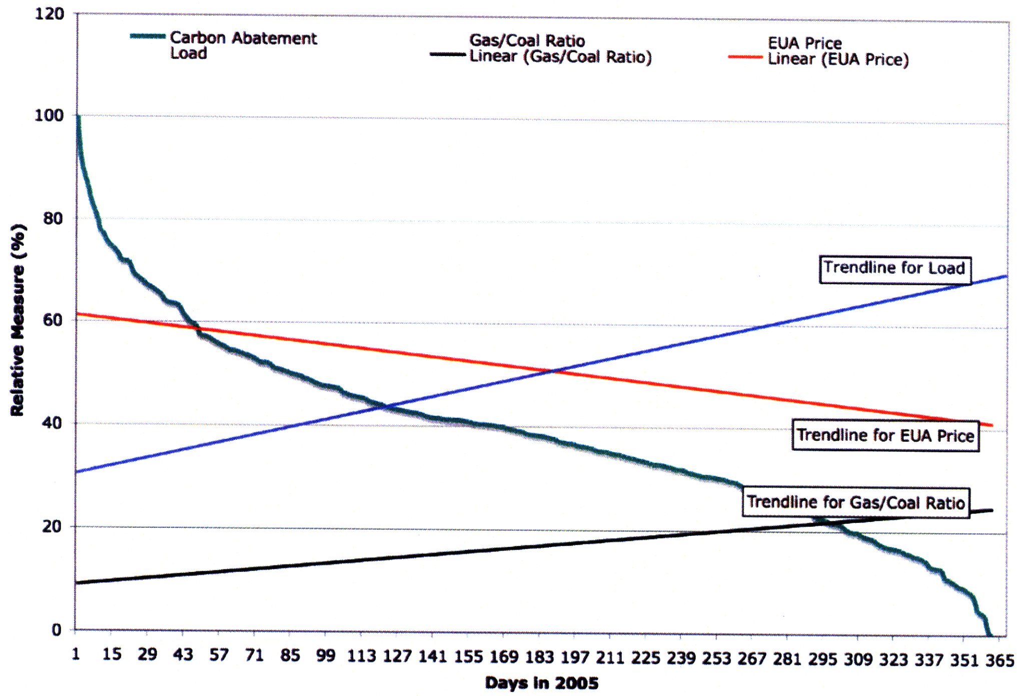


Figure 2.8: Days in 2005 ordered from high to low abatement

Source: Model results, Bloomberg

The estimates of abatement provided here compare well with the estimates for the EU as a whole that have been provided by Ellerman and Buchner (2008, p. 34), when they speak of between 50 and 100 million tons, or of 2.5% to 5%, for each of 2005 and 2006. The similar top-down estimate for Germany that is developed in this paper tends to the upper end of this range on a percentage basis; however, they also clearly include other factors, particularly in 2007, which cannot be attributed to the EU ETS. Minimum estimates can be provided by realistic bottom-up simulations of the power sector alone. The calibrated EU-wide simulation that is reported more extensively in Delarue, Ellerman and D'haeseleer (2008, p. 29), and used here, provides an estimate of 13 million tons for Germany (and 53 million tons for the EU as a whole) for the years 2005 and 2006 combined. These minimum estimates are approximately 1.3% of both German and EU-wide emissions, on the unlikely assumption that the only abatement in response to the CO2 price was in the power sector and in that sector only by fuel switching. The exact number or percentage is not as important as the evidence that there was some effect, although it was modest in keeping with the emission reduction ambitions of the trial period of the EU ETS.

2.3 The implications of Short-term Effects on Long-term Investment Decisions

The bottom up models provide a crucial link for the long-term investment decisions. The E-simulate model in its least cost hourly approach also calculates the marginal fuel at every hour. Assuming that the marginal plant will have to compete with the existing generation fleet and does not directly replace other capacity, the marginal fuel can be taken as an indication for the number of hours the new plant will be dispatched, and hence the capacity factor. This is one of the most sensitive variables in the discounted cash flow model that will be introduced in more detail in Chapter 4.

Taking the results from the bottom-up model, the hours per marginal fuel can be aggregated to find how many hours per year coal is the marginal fuel on the grid.

Table 2.3: Marginal Fuel Calculations for the year 2006

2006

Fuel	Conversion type	Min. up time (hrs)	Raw Count	Percent	Adjusted for Ramp Time	
Coal	Rankine multifuel	12	5369	61.29%	**61.28%**	**Coal**
Gas	Rankine gas	4	1085	12.39%		
Gas	Brayton-Rankine SS	4	106	1.21%		
Gas	Brayton-Rankine DS	4	1902	21.71%	**38.72%**	**Gas, Diesel, Fuel oil**
Gas	Brayton	1	55	0.63%		
Diesel	Diesel	1	2	0.02%		
Fuel oil	Rankine oil	4	241	2.75%		

Source: E-simulate model

Table 2.4: Marginal Fuel Calculations for the year 2005

2005

Fuel	Conversion type	Min. up time (hrs)	Raw Count	Percent	Adjusted for Ramp Time	
Coal	Rankine multifuel	12	5459	62.32%	**62.31%**	**Coal**
Gas	Rankine gas	4	609	6.95%		
Gas	Brayton-Rankine SS	4	51	0.58%		
Gas	Brayton-Rankine DS	4	2224	25.39%	**37.69%**	**Gas, Diesel, Fuel oil**
Gas	Brayton	1	65	0.74%		
Diesel	Diesel	1	7	0.08%		
Fuel oil	Rankine oil	4	345	3.94%		

Source: E-simulate model

Aggregating the raw numbers for the year 2006, this results in 61% of hours with coal as the marginal fuel. If the numbers are adjusted for the minimum up times required, the numbers do not change significantly and 61.3% of the hours find coal as the marginal fuel, while 38.7% of all hours find gas as the marginal fuel. This analysis forms the basis for using a capacity factor of 0.4 for the peak gas dispatch in the following chapters. If one assumes that the short-term marginal cost of a gas plant is higher than the marginal coal plant after adjusting for the price of carbon, this results in a low capacity factor for gas and hence a significant deterioration of the profitability of a gas investment. Repeating this analysis for 2005 shows very little difference even though the carbon prices had been significantly higher, suggesting that the impact of the carbon price is not significant.

These results will be discussed in more detail in the context of fuel spreads and capacity factors used in the investment model in Chapter 5. Before the long-term investment model will be discussed, however, the following chapter will look more broadly at evidence of changing investment behavior as a consequence of the introduction of carbon emissions trading in Europe and specifically in Germany.

3. Long-term Investment Effects and Evidence of Changing Investment Decisions

The short-term effects of carbon pricing have been established in the literature using bottom-up models such as the one presented in the previous chapter; however, methods for estimating the long-term impacts of carbon pricing on power investments are much less established. This is in part due to the fact that there are merely four full years of data available in Europe. Furthermore, three competitive and game theoretic considerations make companies less willing to fully and openly disclose their actual assessment. Firstly, individual plant-level cost structures and portfolio merit orders are kept secret from to avoid being underbid by competitors. Secondly, companies want to maintain a strong bargaining position vis-à-vis the regulators and the European Commission to ensure that the power plant and company receives the highest possible carbon credit allocation. Thirdly, the real options embedded in the company's growth portfolio are dependent on specific regulatory and market outcomes related to carbon and power prices which means that investment plans are contingent on expectations of price and allocation effects. While the next three chapters will discuss these elements in more detail, this chapter provides a literature review of long-term effects and presents empirical data that shows how Germany has not followed the European trend of investing in gas-fired generation assets.

3.1 Literature Review

Given the 25-40 life of power plant investments, any changes to the generation portfolio will be of a gradual nature and investment decisions are unlikely to be influenced by short-term movements in price. The long-term effect of emissions trading on power investments is contested among industry experts. Depending on whether one classifies CO_2 emissions trading as a marginal change of fuel prices or a long-term change of the industry, the conclusion of the effect of emissions trading on long-term investment decisions is either only seen on short-term fuel change and marginal carbon abatement or the structural change of investment viability in specific generation technologies. The literature on the long-term investment effects of carbon trading for the power sector is still relatively scarce. The literature review shows that so far analysis has focused on normative approaches, cost distortions as well as real options and examples will draw both on carbon emissions trading as well as experiences from the US SO_2 trading system.

Normative Approaches

Brewer (2005) uses surveys to assess the level of knowledge within firms prior to Phase I of the EU-ETS and assesses company actions to increase their preparedness to emissions trading, which, at the time of the study was still surrounded by significant uncertainty. Pinske (2007) uses the large database of carbon related information compiled through the Carbon Disclosure Projects to assess the intentions of a global sample of companies in dealing with the consequences of a carbon price. Curiously, companies had very similar responses regardless of them being European firms or outside of a mandatory carbon trading framework which is explained with the focus on global climate change policy in general rather than carbon pricing in specific. Several other studies look at the preparedness of specific industries in specific countries, including Paulsson and von Malmborg (2004) in their analysis for Sweden.

Cost Distortions on a Macro and Firm level

A second set of studies has analyzed the changes in cost structures and distortions introduced through elements of carbon emissions pricing. The first seminal papers on the economic implications of emissions trading rules stem from Weitzman (1974) and Atkinson and Tietenberg (1987). A crucial part of this analysis is to assess the impact of different emissions allocation mechanisms. Ellerman, Joskow and Harrison (2003) reflect on experiences, lessons and considerations from emissions trading in the US. Busch, Weinhofer and Hoffman assess the carbon performance of the 100 largest US electricity producers as well as potential carbon exposure of these companies. Neuhoff, Martinez and Sato (2006) discuss the impacts that the national allocation plans (NAP) have on market prices, operation and investment decisions and provide numerical examples to support these findings. Gagelmann and Frondel (2005) review the literature on similar issues faced by other emissions trading schemes such as the US SO_2 system. Schleich and Betz (2005) review the impacts that allocation mechanisms have on incentives to innovate. Oberndorfer and Rennings (2007) assess the competitiveness impacts on the companies that result from the EU ETS. Ellerman (2006) provides insights on distortions from new entrant and closure provisions while Ellerman and Buchner (2006) assess abatement and allocation effects in their preliminary analysis of the EU-ETS. Sekar, Parsons, Herzog and Jacoby (2006) give a concrete example how carbon price and policy scenarios present tradeoffs between coal generation technologies. Hoffmann (2007) assesses the effects of carbon trading on investment decisions through expert interviews and finds limited impact on investment or R&D decisions. Hepburn, Grubb, Neuhoff and Mathes (2006) review the fundamental basis for auctioning within the EU-ETS.

Real Options in Capital Investment Decisions

Laurikka and Koljonen (2006) apply a real options methodology to analyze the impact of carbon price uncertainties in future power plants. Their study of the Finnish power sector comes to the conclusion that there are two specific real options embedded in the capital allocation problem, the option to wait and the option to alter the scale of the operations and the impacts of allocation methodologies on these options is discussed in detail. Yang and Blith (2007) provide a comprehensive model for assessing risks and uncertainties of policy risk and carbon price uncertainty on the long-term investment decisions of power generators. Uncertainty is modeled as short-term volatility, longer-term random walk price variations (Brownian motion), as well as climate policy uncertainty that leads to step changes in price after price shocks are triggered by discrete changes to the market. The authors then provide a comprehensive modeling approach using real options to quantify the value of flexibility and to determine the optimum investment point given the expectations on the carbon regime. In addition to looking at the changes in merit order between coal and gas investments and the associated carbon pass-through, Yang and Blith also consider the development of CCS technology and calculate carbon price thresholds required to incentivize CCS development.

3.2. Evidence of Investment Decisions Pre- and Intra- Phase I

Before developing the investment model to analyze long-term effects, this section will assess recent empirical evidence of trends within the industry two years into the second phase of European carbon trading. Both the current generation portfolio and announced investment plans are taken into consideration to see whether there are any early indications of structural change in the power generation industry.

Method and sources of empirical evidence

Empirical evidence is gathered from annual reports, analyst reports and technical reports of the large power generation companies. Germany has four large incumbent utilities, E.On, RWE, Vattenfall, and EnBW (referred to as "Big 4"), which define the oligopolistic structure of the European and especially German markets. Aside from aggregating data from the large four companies separately, another data source is the German economics ministry, which collects and publishes aggregated statistical data series. Furthermore Platts has developed a database of EU-15 wide power plant construction and investment announcements, which has been tracking the sector since 2002. Moreover, the German association of electric power and water companies, BDEB, publishes a database of power projects and tracks the projects from announcement, through the licensing stage and into the construction and completion stage. While this data is only available as a current snapshot of the industry rather than a time series, the data is the most detailed and most up to date. Initially a timeseries had been constructed based on data from mid-term investment plans of the Big 4 players. This idea had to be abandoned, though, due to the large reporting inconsistencies between companies, changes in regional aggregation and changes in time scales for projects.

European Trend towards Gas strong, Coal stalled briefly by EU-ETS

Investment in power generation assets in the EU has been focused on incremental builds in gas, coal, wind and waste. The macro data seems to suggests two very clear price and policy trends. In gas, the growth of expected capacity can be explained with the expectation of more stringent carbon regulation while the drop in activity from 2006 to 2007 most likely is a reflection of the high gas price and the higher gas to coal price ratio.

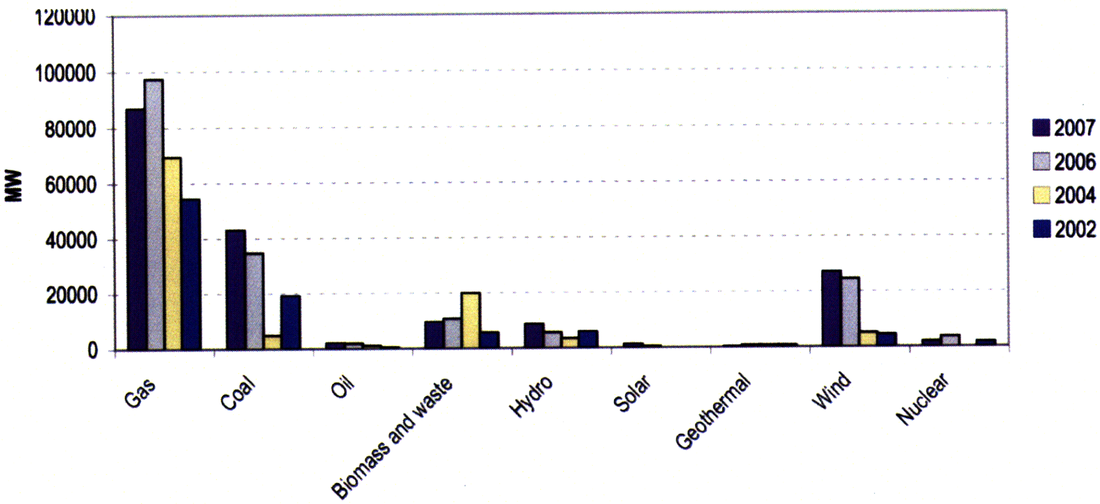


Figure 3.1: EU 15 Power Plants Planned and Under Construction

Source: Platts Database

It is exactly this ratio which seems the most intuitive explanation of the recent increase in coal build, although the total capacity of coal (at 43 GW in 2007) is about half of the total planned gas capacity (still at 87 GW, down from 97 GW in 2006). The sharp drop in coal plant plans in 2004 is likely a reflection of the negative impacts that a carbon price would have on the relative profitability of coal. The clear preference for gas and renewables over coal is evident from this EU 15 chart; however it stands diametrically opposite to power plant build in Germany which is shown in Figure 3.2. German planned generation capacity investments are 70% coal and 20% gas for projects that are currently being built or already have a license. For projects in the planning or approval stage, 63% are coal while 33% are gas. This could reflect trends towards more gas, but still shows a clear preference for coal that runs contrary to investment trends in the rest of Europe. To explore possible reasons, it seems pertinent to look at the ownership structure of generation assets in Germany and specifically the dominance of the four largest utilities.

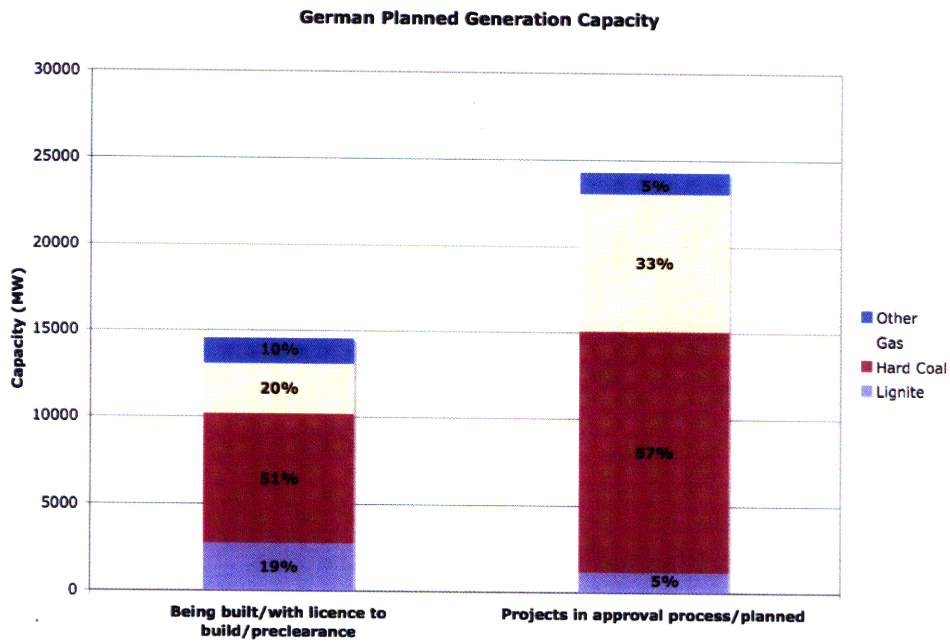


Figure 3.2: German Planned Generation Capacity by Fuel and Completion Stage

Source: BDEW

The Big 4 players account for two-thirds of the total power generation assets in Germany, owning the majority of coal and nuclear assets. The companies are, however, minority holders in gas and renewables.

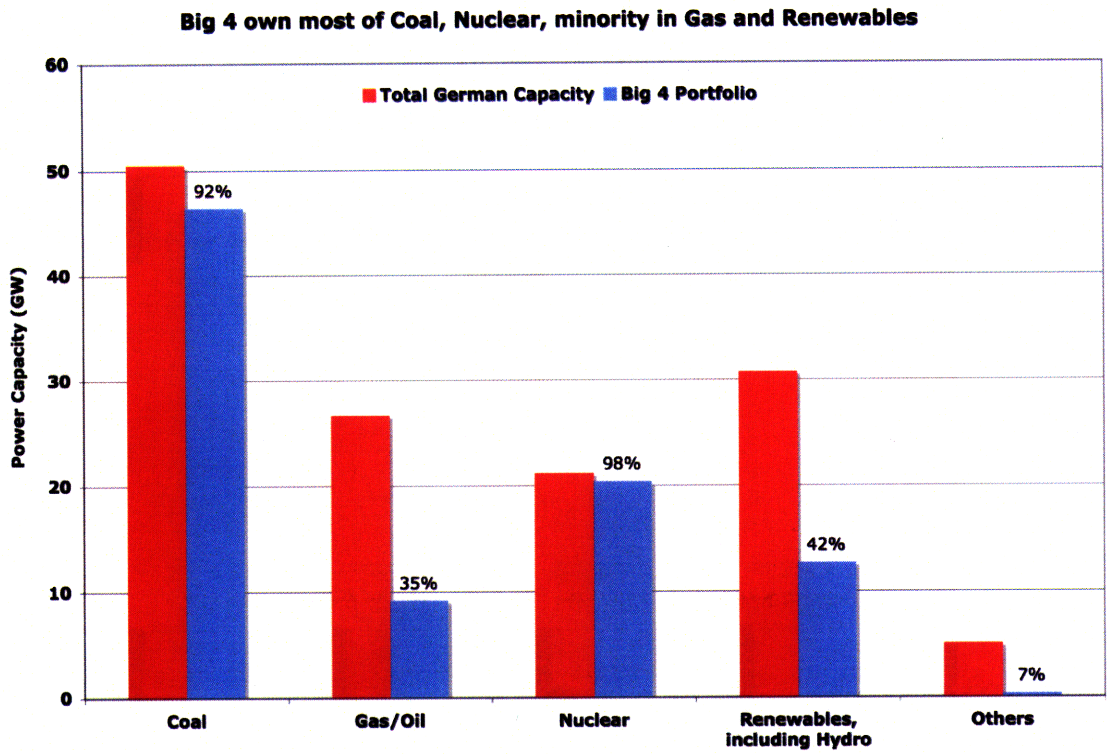


Figure 3.3: Ownership of assets by Fuel Type of Big 4: E.ON, EnBw, RWE, Vattenfall

Source: Company Annual Reports, Federal Economics Ministry

The Big 4 own almost all lignite, hard coal and nuclear assets, they own only 42% of renewable assets, a large part of which is hydro, and 35% of natural gas and oil assets. Historically, the Big 4 have been best positioned to make high capacity, large capital investments and smaller local utilities. They have focused on the lower upfront cash cost, smaller capacity investments that serve distributed communities. Hence marginal investments from these companies are likely to be geared towards large baseload investments such as coal.

Generation Portfolio hardly changes during ETS-Phase I

Unsurprisingly due to the large life times of power investments, the overall generation portfolio of the Big 4 did not change significantly before and during ETS-Phase I. Marginal increases in gas capacity and marginal decreases in nuclear capacity have let the total generation capacity of the Big 4 companies hover around 90 GW in the five years between 2003 and 2007.

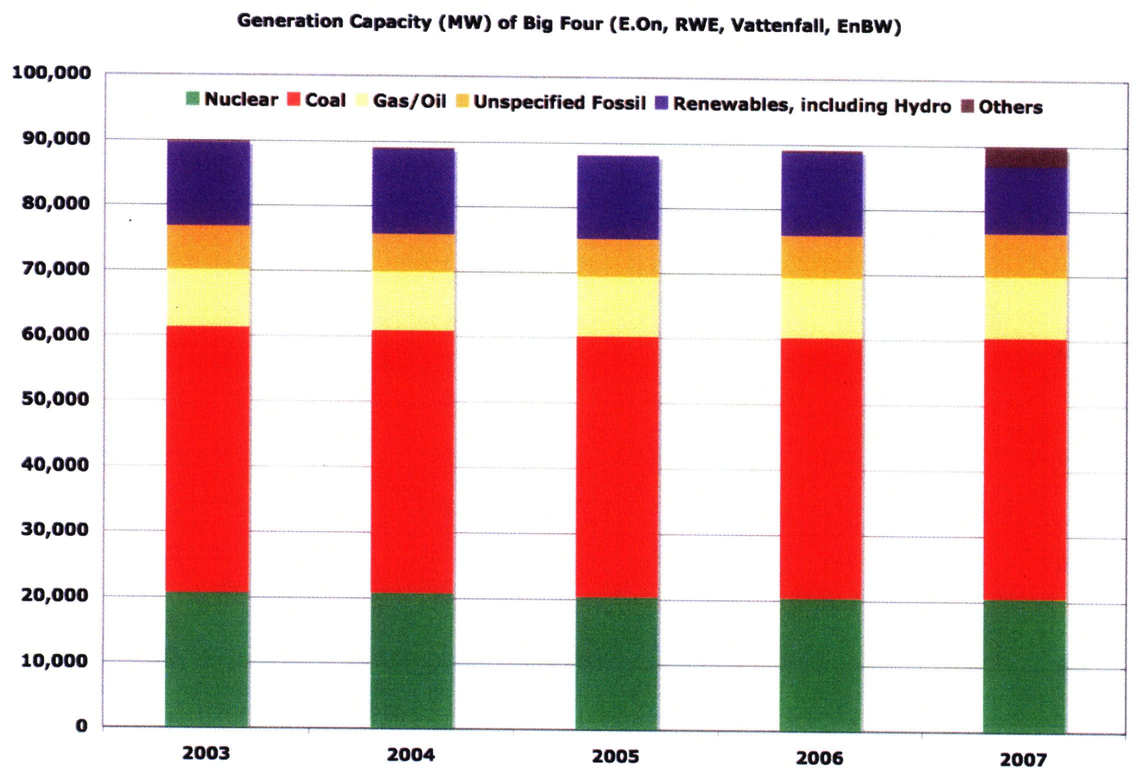


Figure 3.4: Generation Capacity of Big Four

Source: Company Annual Reports

Significant Investment Plans before Phase III

Investment in additional generation capacity is driven by several factors. Firstly, several coal power plants are reaching their planned retirement age and are likely to be replaced. Secondly, power demand has risen steadily over the past decade requiring new capacity. As incremental demand is currently being met almost entirely from non-fossil sources, there is the need for baseload capacity. Thirdly, the nuclear phase-out laws of Germany will retire nuclear power completely by 2021, although future administrations could decide to revoke this law as early as 2010, should neither the Green Party nor the Social Democrats be part of the ruling coalition following German elections in September 2009. While the current economic crisis will dampen demand, the long-term need for additional capacity has resulted in the industry increasing investments and pledging significant new investments in the next years.

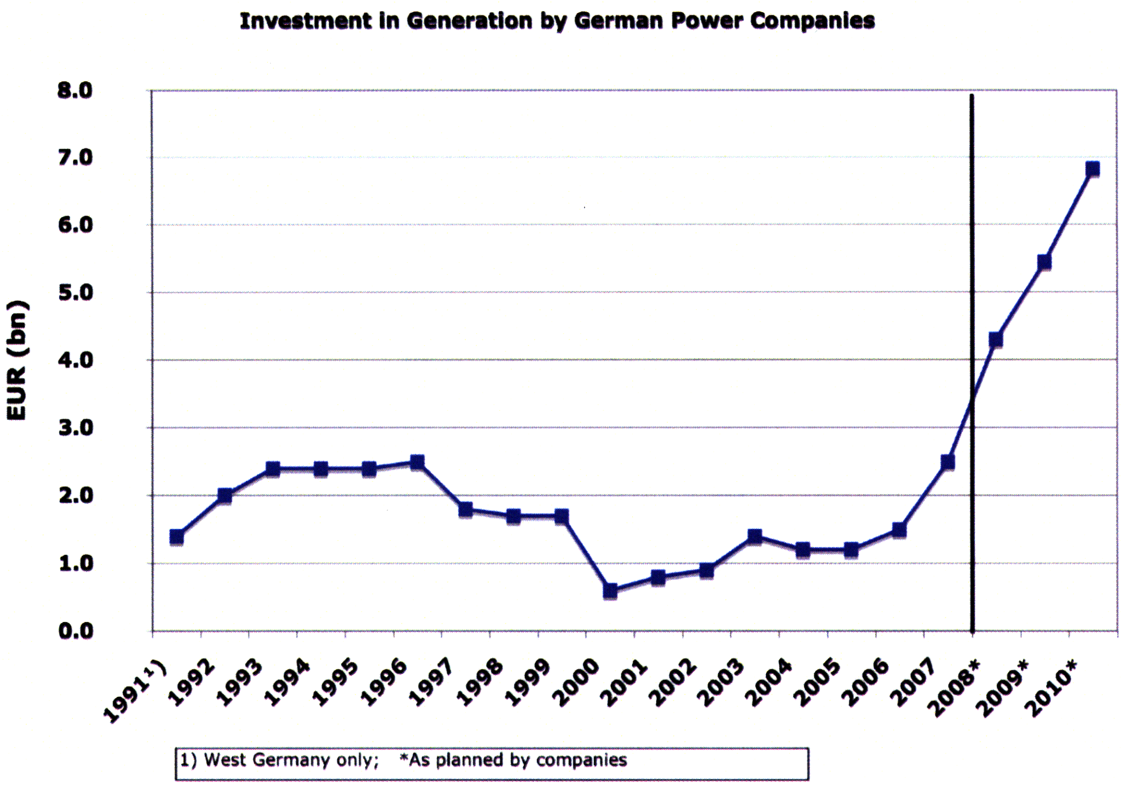


Figure 3.5: Investment in Generation Capacity by German Power Companies

Source: BDEW

Following the German reunification, power companies have invested an average of 1.7 bn Euros annually in new generation while spending an average of 3.6 bn Euros annually on transmission and other capital investment projects. Following the projections of the power company as reported by the industry association, BDEW, this trajectory is set to increase through to 2010 when power companies expect to invest close to 7 bn Euros in generation capacity alone. In real terms this amount of investment has not been seen since the mid 1970s, and then again in the mid 1980s, when a significant part of the current generation fleet was built.

A more detailed view on the technology preference of these investments is provided by the BDEW, the German power and water utility industry association that publishes up-to-date statistics of all announced power plant announcements and traces projects through the regulatory pipeline. As of January 2009, 14.5 GW of new capacity were either under construction or had received building licenses or building pre-clearances. This represents

16% of the current Big4 generation portfolio and 11% of the total German power generation assets. An additional 9.7 GW of capacity is currently going through the approval process; 10.2 GW of capacity have been announced to be built with operation to begin before 2014, while 3.1 GW of capacity are planned to come to operation after 2014, 1.2 GW of projects are currently conducting citing studies.

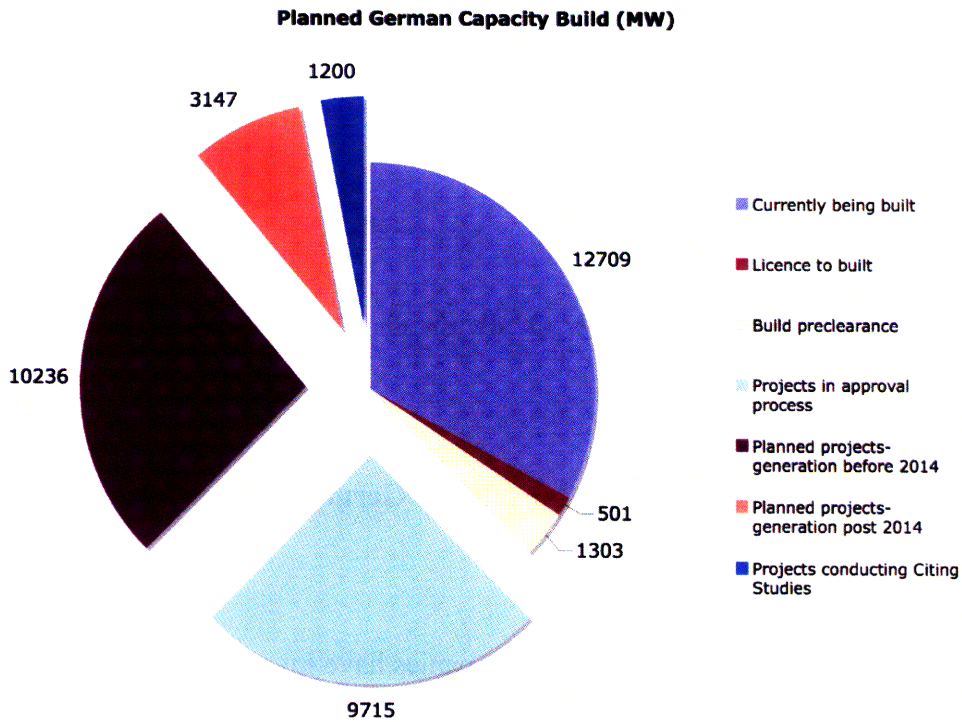


Figure 3.6: Planned German Capacity Build by Construction Stage

Source: BDEW

The 24.3 GW of currently planned capacity represents 27% of the current Big4 portfolio and 18% of total German generation assets while the entire 38.8 GW of capacity that is either being constructed or in the pipeline represents 43% of the Big 4 and 29% of the entire German capacity. As shown in Figure 3.2 more than two thirds of this investment will likely be done in coal.

Table 3.1: Planned Capacity Pipeline compared with Big 4 and Total German Assets

	Capacity (GW)	As Percentage of Current Big4 Portfolio	As Percentage of total German Generation Assets
Capacity being Built as of Jan 2009	**14.5**	**16%**	**11%**
Capacity in the Pipeline	**24.3**	**27%**	**18%**
Sum of Capacity being built and in pipeline	**38.8**	**43%**	**29%**
Sum Big 4 Capacity 2007	89.8		
Sum Germany Capacity 2007	134.3		

Source: BDEW, Company Annual Reports, German Federal Economics Ministry

These statistics underline the fact that many power generation companies are in the process of deciding which technology to use for additional capacity. Even if the European economy is heading towards a long recession and power demand is slowing over the coming quarters, this investment decision will have to be revisited as soon as the economy will recover and demand growth returns to historic trajectories of 1-2% per annum. The following chapters will serve to outline the investment model to provide an understanding for such preference, and they will analyze how carbon trading has both price and allocation effects on the long-term investment decisions.

4. Power Plant Investment Model and Analysis of Key Uncertainty Parameters

Long-term investment decisions by their very nature are characterized by significant uncertainties. As presented in the previous chapter, more capacity needs to be built over the medium-term, yet companies must decide in which generation technology and what fuel to invest. While commodity markets express price expectations for the next several years through forward curves, no long-term indicators exist over the entire expected life of a power plant. A frequent tool used when trying to forecast the future is to develop scenarios that will reflect optimistic, pessimistic, or the base case assumptions. However, scenarios make it hard to judge the relative likelihood of these scenarios occurring, which is why a probabilistic approach is chosen. Hence, rather than using static price assumptions, a time series of historic data is fitted to a distribution. Using Monte-Carlo methods, 10,000 samples are then drawn randomly from the distributions of the different variables.

Over the next three chapters, the investment model and its main variables will be presented and the model outcomes discussed in detail. The effects of the carbon price on the power sector can be divided into two separate drivers, price and allocation. This chapter will introduce the discounted cash flow model of a coal and gas investment while the full discussion of price effects will be done in Chapter 5. The allocation effects will be discussed in detail in Chapter 6.

4.1. Representing Uncertainties in Investment Model

The centerpiece of calculating the profitability of power generation investments is the use of a discounted cash flow model both for a coal and gas power plant. The model calculates the net present value (NPV) of the investment over the project lifetime, as well as the internal rate of return (IRR) of the project cash flows. More formally, the NPV is the sum of the future cash flows discounted using the weighted average cost of capital, specified mathematically as:

$$NPV = \sum_{t=t_1}^{T} \frac{R_t}{(1+i)^t} \qquad (1)$$

with t_1 = project construction start;

T = end of lifetime of investment which is 25 years for gas plant and 40 years for coal investment;

i = interest rate which is set at the weighted average cost of capital (WACC)

The internal rate of return is defined formally as the interest rate, i, that would make the NPV of the project zero and can be solved directly from the NPV formula or iteratively. The investment model is implemented in Excel and sample results can be found in the Annex II.

Technical assumptions for the Coal Investment Model

There are several technical assumptions required for the coal investment model. To the extent possible, the assumptions are taken directly from the same sources that were also used for the bottom-up E-simulate model, so as to provide the biggest sense of cohesion between the short-term and the long-term models. The overall specifications assumed for the coal power plant are a Rankine 500 MW coal plant, with a 40 year life span, running at a full load efficiency of 40%, and a capacity factor of 0.85 to produce 3.7 TWh of power per year. The full technical assumptions are provided in the table below:

Table 4.1: Technical Assumptions for Coal Plant

Technical Assumptions for Coal Plant:	
Plant Size (MW)	500
Cap. Cost: mn EUR/MW	*0.9605*
Heat Rate (Btu/Kwhe)	*8530*
O&M Cost Fixed (mn EUR/MW)	*0.033*
O&M Cost Variable (EUR/MWh)	*2.502*
Coal Consumption (mn Btu)	31757190
Carbon Emissions Factor (t CO2 / MWh)	0.918
Capacity Factor	0.850
Power Produced per year (mn KWh)	3723
Lifetime	40
Full Load Efficiency	40%

Source: E-simulate and model calculation

Technical assumptions for the Gas Investment Model

Like the coal model, the assumptions used in the gas investment model use the same underlying sources that were also used for the bottom-up E-simulate model, so as to provide the biggest sense of cohesion between the short-term and the long-term models.

The overall specifications assumed for the gas power plant are based on a 300 MW Brayton-Rankine gas plant, with a 25 year life span and a full load efficiency of 52%. The gas power plant can be dispatched in two different means, either at a high capacity factor bidding for base load power prices or at lower capacity factors bidding for peak load power prices. When dispatched as a peak power plant with a base case assumption of a capacity factor of 0.4, it produces 1.1 TWh of power per year, while a base load configuration would use a base case assumption of 0.85. The capacity factor of 0.4 has been chosen, based on the marginal fuel analysis shown at the end of Chapter 2. Given that the German power grid has coal as the marginal fuel for significant parts of the year, these assumptions might be very optimistic as will be shown in the following two chapters. The full technical assumptions for a peak load configuration are provided in the table below:

Table 4.2: Technical Assumptions for Gas Plant

Technical Assumptions for Gas Plant:	
Plant Size (MW)	300
Cap. Cost: mn EUR/MW	*0.4133*
Heat Rate (Btu/Kwhe)	*6562*
O&M Cost Fixed (mn EUR/MW)	*0.02475*
O&M Cost Variable (EUR/MWh)	*1.5*
Carbon Emissions Factor (t CO2 / MWh)	0.350
Capacity Factor	0.40
Power Produced per year (mn KWh)	1051.2
Lifetime	25
Full Load Efficiency	52%

Source: E-simulate and model calculation

Financial assumptions used in both Investment Models

There are a number of standard finance assumptions that have been used both for the coal and gas power plant investments. For example, the model assumes that the investor already holds a diversified portfolio and the credit rating agency does not penalize the investor's credit rating for the investment decision taken.

Table 4.3: Finance Assumptions used both in coal and gas plants

Finance Assumptions:	
Disc. Rate = WACC	8.40%
Tax Rate	28.3%
Inflation	1.50%
Insurance/Tax	0.0178%
Depreciation	6.3%

Risk Free Rate	4.00%
Ke	12.00%
Kd	6.00%
Debt Fraction	60%

Source: E-simulate and model calculation

The tax rate of 28.3% and a depreciation rate of 6.3% were taken from an Ernst&Young (2007) publication on representative power investments in Germany. It is assumed that the power plant will be financed using 60% debt and 40% equity. Given the current credit environments, it is questionable whether utilities could actually receive 60% debt financing for new projects, a point which disadvantages coal investments versus gas due to the higher capital intensity. While current investment projects will potentially be delayed or require a higher equity portion (which erodes returns), we assume that the current scarcity of large credit financing facilities is a temporary effect.

4.2. Uncertainty of Commodity Input Prices

As seen from the short-term effects discussed in Chapter 2, fuel prices take a central role in determining the marginal fuel choice. The price distribution hence becomes one of the central assumptions for any long-term investment model, having a large impact on the projected economic returns of a power plant over the coming 25-40 years. The long-term price forecasts through simulation are required, given that the forward curves, observed in the commodity markets, seldom reach beyond 5 years into the future and forward-selling of power tends to occur only one to two years into the future.

Distribution Fitting:

The method for the probabilistic analysis of the data requires the historical data to be fitted to standard distributions, from which the Monte Carlo Simulation can then randomly draw samples. The distribution fitting was performed using MATLAB as well as the distribution fitting software Crystal Ball 11.0, a software produced by Oracle that allows very easy and rapid fitting of large datasets and allows correlations between datasets to be defined when used together with Monte Carlo methods. Both Crystal Ball and MATLAB fit the data sample to a wide variety of possible distributions and provide the statistical goodness of fits as output upon which the most adequate distribution is chosen. After determining the optimal distribution using the Crystal Ball software, the data was then put into MATLAB, which allows for further analysis and good graphical representations of the fitted distributions.

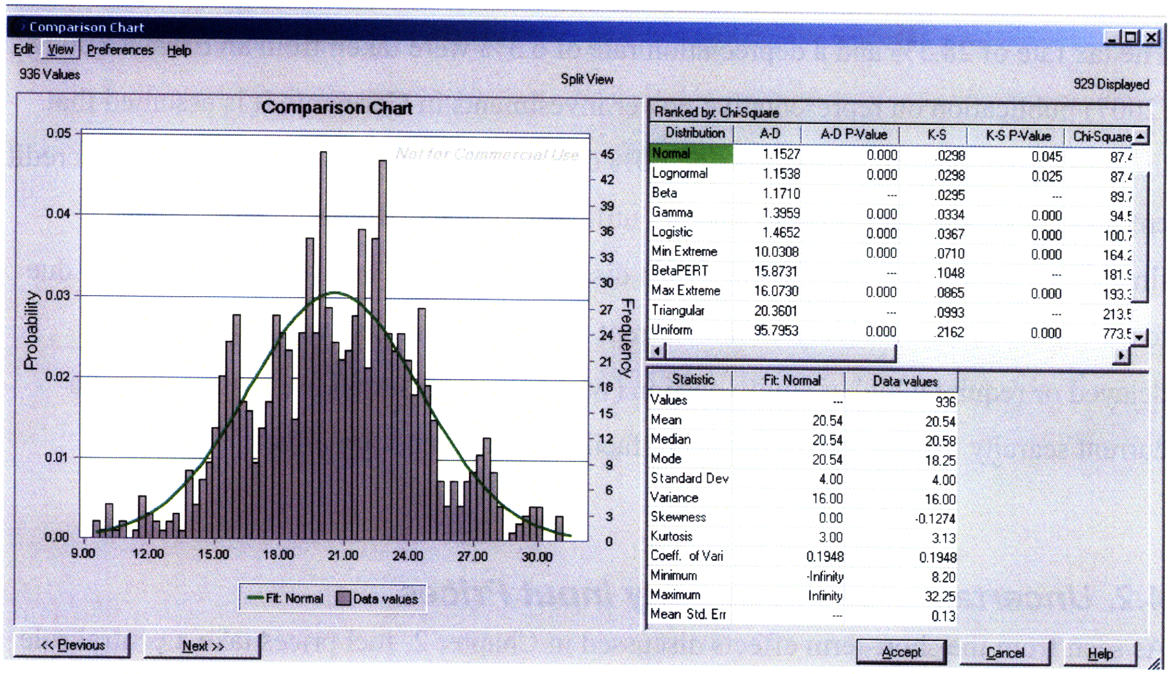


Figure 4.1: Screenshot from Distribution Fitting Software- Crystal Ball

Source: Crystal Ball 11.0 Software

Before discussing the commodity price distributions in detail, there is the question of what time periods to consider for the analysis. The carbon price has only existed since 2005, hence leading to the use of the entire available data for Phase II delivery, since the trial period is now over and prices are very unlikely to ever be this low again. The upcoming chapter 5 on price effects will also show how in the first half of the decade before the introduction of the EU-ETS, gas seemed the more profitable fuel thus justifying new builds. Using 2001 to 2004 commodity prices, gas looks especially appealing when adding a hypothetical carbon price and scenarios are shown for carbon prices of 8 and 15 Euros per ton.

For the commodities coal and gas, longer ranging price distributions were used; this assumes that gas and coal are large regional or global commodity markets that are not impacted by the presence of the carbon price. While this is definitely the case for the global coal markets, the same assumption is made for gas, since the development of global LNG terminals is rapidly integrating global gas sub-markets into a single, interconnected market similar to the oil market. The table below also shows alternative commodity prices that have been used in other scenarios outside of the base case. Had recent gas and coal prices been used, the returns would have been lower since the mean values of the commodity costs would have been higher. Since a strong argument of this thesis is that fuel prices are potentially dominating carbon price effects, the choice of a viable fuel price series is crucial to the analysis. What is important to notice, however, is that gas prices have seen relatively large swings in tandem with oil prices several times in the last decades, while the recent coal price spike is a phenomenon that has not been seen so far. Hence all long-term coal price projections are lower than those of gas, but in the interest of taking a conservative approach in the analysis, relatively high coal prices have been chosen nonetheless. Another crucial factor rests with long-term delivery contracts that are often not fully disclosed for commercial reasons. The analysis is based on forward prices seen on the market, assuming that companies could potentially sell into these markets, if that was possible. Lower fuel prices would necessarily lead to higher returns and potential distributions are shown in the table below.

Table 4.4: Overview of data inputs for price distributions

Data Series:	Units	Mean	Distribution Type
Gas-2000-2008	EUR/TJ	4244.59	Log-normal
Gas-2005-2008	EUR/TJ	5860.60	Normal
Coal-2000-2008	EUR/t	57.56	Log-normal
Coal-2005-2008	EUR/t	74.38	Log-normal
Carbon: 2005-2008- Dec 09 contract	EUR/t	20.40	Normal
Power-Base: 2000-2008	EUR/MWh	36.64	Beta
Power-Base: 2005-2008	EUR/MWh	51.51	Log-normal
Power-Peak: 2000-2008	EUR/MWh	70.97	Log-normal
Power-Peak: 2005-2008	EUR/MWh	71.76	Beta

Source: Model inputs. For a detailed listing of all distributions refer to Annex I.

Coal Price

Several coal prices were taken into consideration as the basis for the price distribution used in the coal investment model. The German import prices for hard coal are reported on a monthly basis, which is not sufficiently frequent to use in conjunction with daily carbon and power prices. Another option would be to use the standard world market price for coal, such as the API #2 ARA coal price series. The drawback of this price series is that it does not consider transportation costs (although this could be adjusted for) and that the time series available for use showed gaps for any data prior to 2005. Using a European or global market price will ignore any benefits that backward integrated players reap from access to cheap resources, yet assuming that utilities have the option of selling the coal into forward markets removes any distorting effect on dispatch. The price series used for the analysis was a daily coal index developed by Merrill Lynch that reflects an average of OTC coal prices from independent brokers for the global coal price (CIF ARA). The index is based on forward contracts that roll over quarterly. This index has been scaled to the German monthly price data to reflect the prices including transportation costs faced by power companies while capturing the daily volatility in prices. As the prices used for the distribution are from January 1, 2001 until March 10, 2009. The fit of the price data is not very good in statistical terms, due to the high price fluctuation and the coal price spike observed in 2008. Using MATLAB's distribution fit tool, one of the best fits for the data sample is a lognormal function with $\mu = 3.93889$ and $\sigma = 0.3404$. The data histogram and fit is shown below:

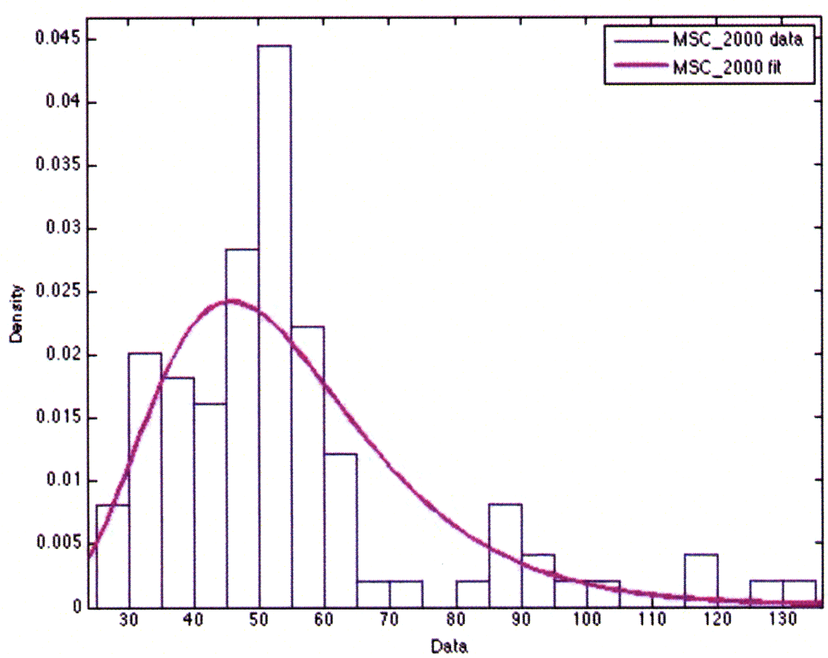


Figure 4.2: Histogram and fitted line for coal dataset

Source: MATLAB output

Gas Price

The German gas market lacks full transparency in that most power utilities have signed long-term off-take agreements with gas providers under confidential terms for prices that are often linked to oil price movements using a proprietary formula. The gas data that is published by official sources is the monthly German border gas import price before taxes. Given the large uncertainty of the real prices, the data series used is the Zeebrugge one month forward gas price in the same time interval as the coal price (from 2001 onwards). This price series is used assuming that power utilities continue to have the opportunity to either use gas in their operations or to sell it on the short-term forward market if that is more attractive. The distribution that best fits the historical data series is a Gamma distribution with the factors alpha= 9.77765 and a beta= 457.276. The histogram and fitted line from the Crystal Ball software is shown below:

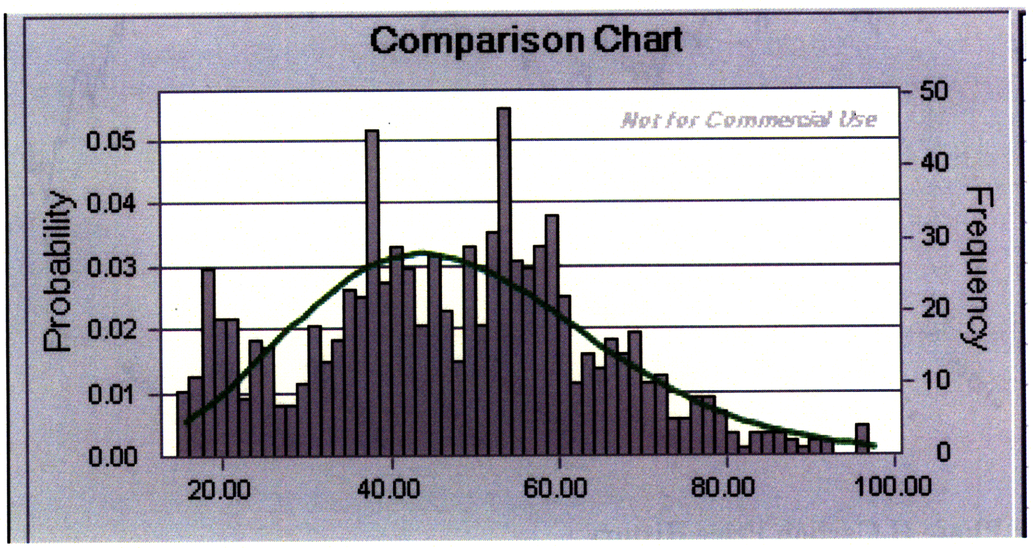


Figure 4.3: Histogram and fitted line for gas dataset

Source: Crystal Ball 11.0 Software Trial Version

Carbon Price

The carbon prices used for this analysis are completely based on Phase II pricing. The Phase I prices have not been included since the first phase carbon credits were not bankable across phases and are not relevant to investment decisions going forward. The European Commission has reaffirmed numerous times its commitment to carbon trading beyond 2012, regardless of whether a post-Kyoto agreement is struck. The complete smooth continuation of carbon trading beyond 2012 is also reflected in the fact that the price spreads between 2012 and 2013 futures contract have significantly narrowed. While the Phase I carbon price showed large volatility, Phase II carbon has been trading in a relatively stable range. Only very lately has the carbon price dropped below the EUR 15 mark, reflecting negative demand growth from the power sector, due to the wider global economic recession.

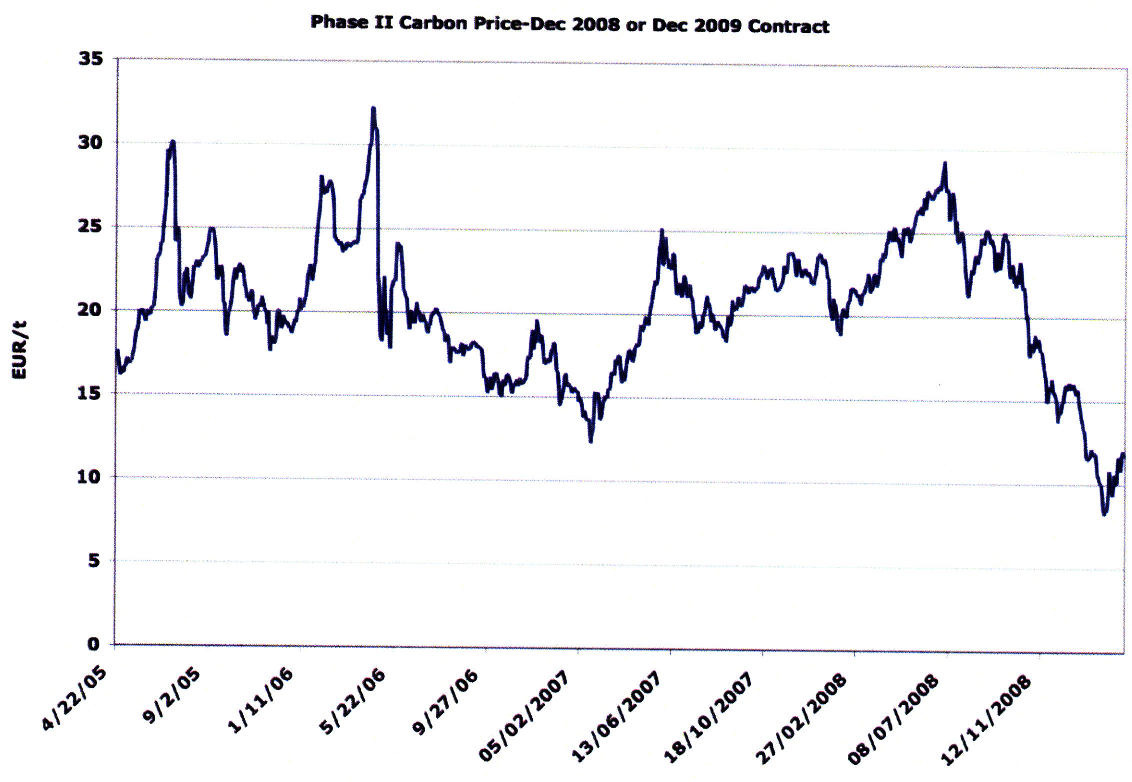


Figure 4.4: Phase II Carbon Price History

Source: European Climate Exchange (ECX)

The carbon price is normally distributed around a mean of 20.40 Euros with a standard deviation of 4.09, as can be seen from the graph below. The data is based on the December 2008 delivery contract quoted on the European Climate Exchange (ECX), one of the main exchanges both for carbon and power in Europe. After the expiration of the December 2008 contract, the price series is based on the December 2009 contract, the next available contract. While this distribution is an accurate representation of the very sparse history of price data, it is more difficult to say how reliable this price distribution is for estimates going forward.

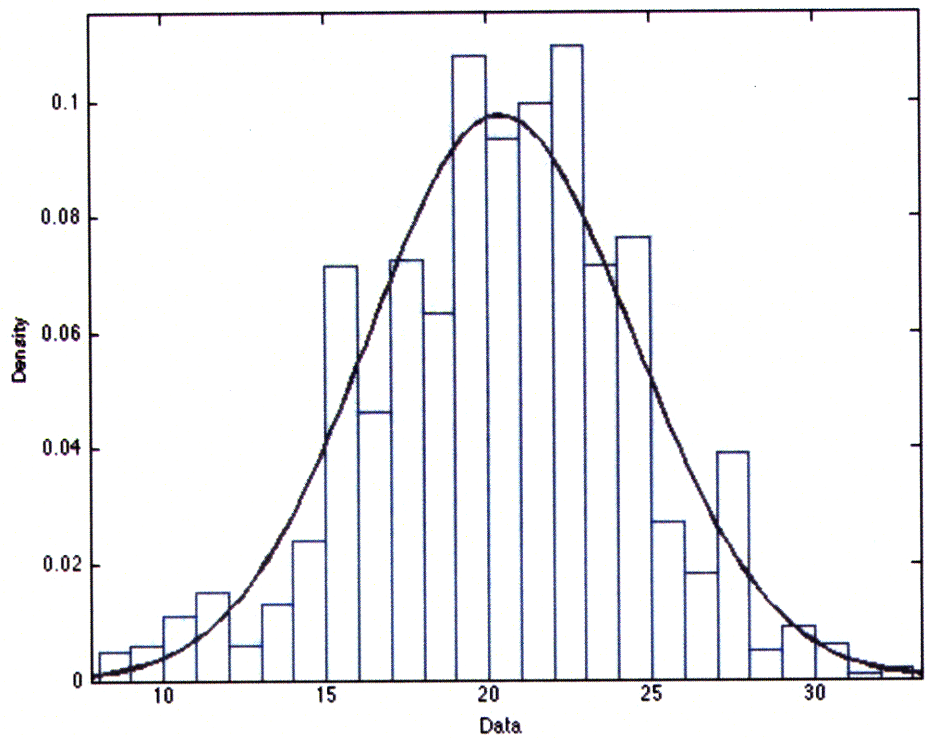


Figure 4.5: Distribution Fit of Carbon Prices

Source: MATLAB software

Given the difficulty in predicting future carbon emissions prices, the sensitivity analysis below compares the profitability of gas and coal investments given different carbon and power price scenarios. The sensitivity analysis assumes the carbon and the power price on the axis as the base starting price in the first year of generation, 2011, and then an annual price increase of carbon and power in line with an expected inflation rate of 1.5%. The base case scenario assumes 85 % free allocation until 2012 and then full auctioning from 2013 onwards, in line with the current state of the European Commission Emissions Trading Directive. The sensitivity analysis shows an investment in a gas asset that has a positive net present value over the life of the project at an initial power price of 50 EUR/MWh at zero carbon price to a power price of 95 EUR/MWh at a carbon price of 150 EUR/t.

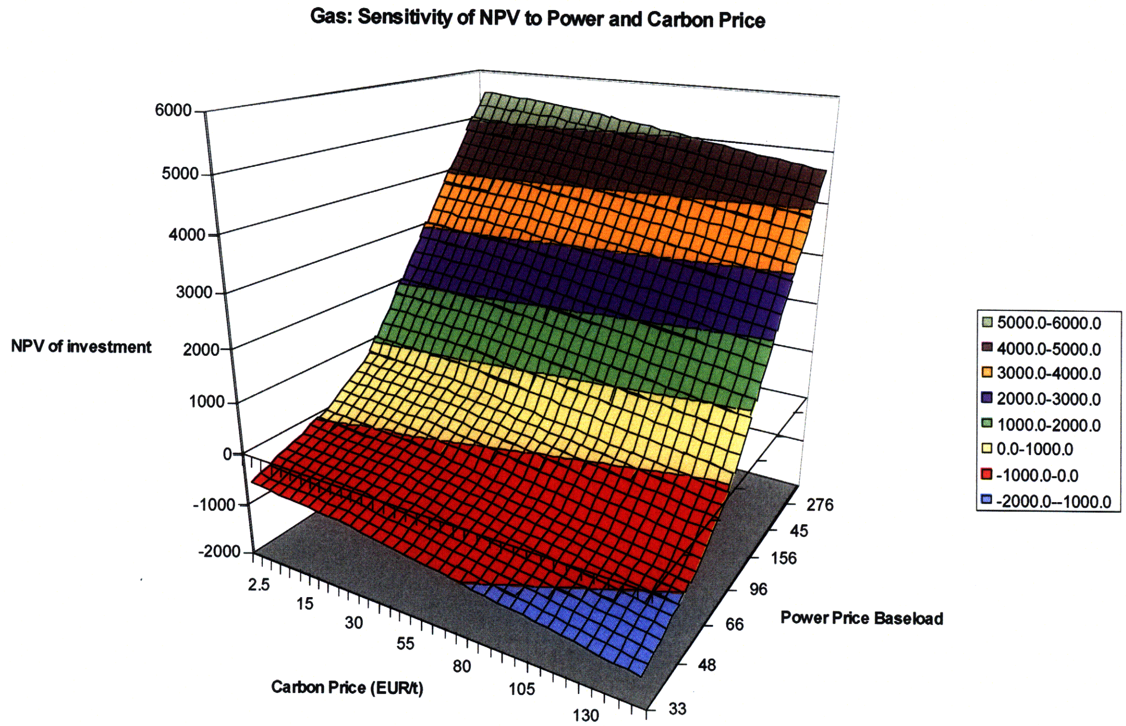


Figure 4.6: Sensitivity Analysis of Gas Investment NPV to Power and Carbon Price

Source: Model calculations

Similarly, the sensitivity of a coal power investment in net present value terms can also be shown as a function of carbon and power prices. The sensitivity analysis merely graphically portrays the sensitivity of coal investments to the carbon price. The coal investment is highly unprofitable at mid to high carbon prices if the power price is low, but conversely, the investment is very profitable in a high power price, low/mid carbon price scenario. The line of break-even (the transition between cream and green colors) runs from a zero carbon price at a power price of 33 Euros/MWh to a carbon price of 130 EUR/t at a power price of 150 EUR/MWh.

All scenarios assume full auctioning beyond 2012 and the base case assumptions for all the other technical and financial indicators. The scenario analysis also keeps the fuel prices constant for every carbon price, thus treating carbon and power prices as fully independent. There actually exists a relatively high correlation between power, carbon and fuel prices, but this will be explored in further detail in following chapter on price effects.

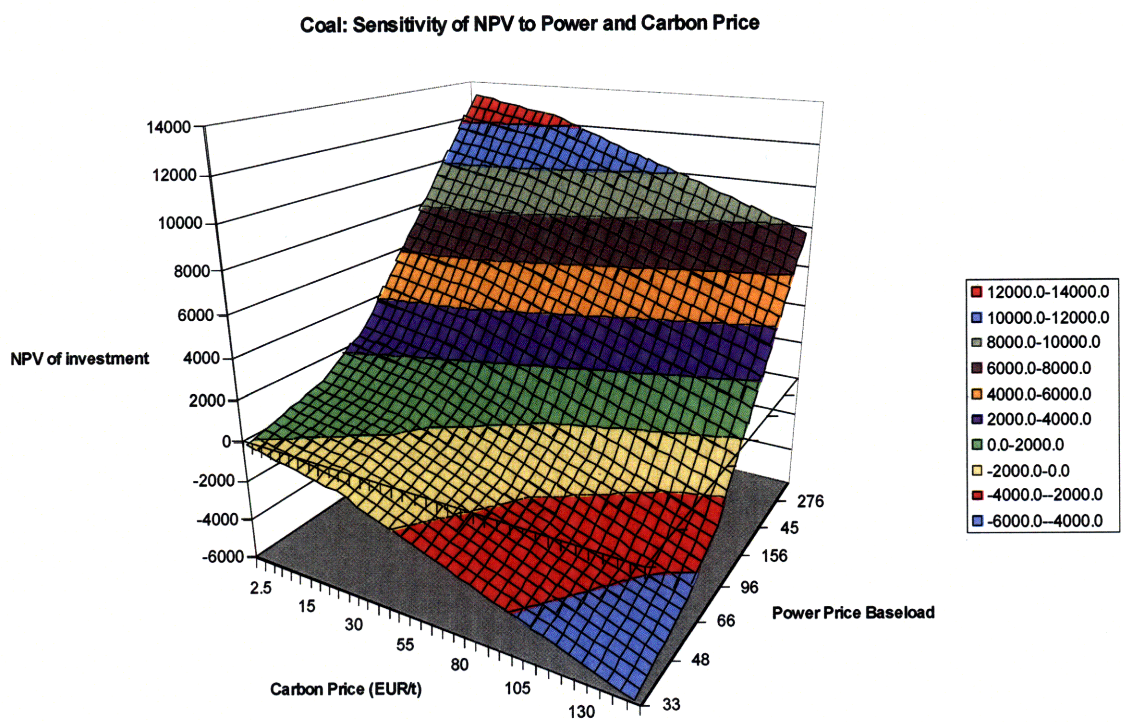


Figure 4.7: Sensitivity Analysis of Coal Investment NPV to Power and Carbon Price

Source: Model calculations

In summary, the difference between the coal and the gas investment profitability reflects the different emission intensity characteristics of the fuels. Thus in a low carbon price scenario, the net present value of the coal investment is positive at a lower power price. In a high carbon price scenario the net present value of a gas investment turns positive at a lower power price compared with the coal plant investment. These insights are intuitive and reflect how these fundamental characteristics are reflected in the investment model.

Power Price

Power prices in Europe differ on a country-by-country basis and large-scale arbitrage between the markets is not possible due to the physical boundaries of power transmission over long distances and across borders. Power prices in Germany have historically been in the mid to high range compared to bordering European states. Regions with lower power prices such as France or the Scandinavian states served by Nordpool, profit from the low cost power generation assets from nuclear and hydropower.

Since the introduction of emissions trading, power prices in Germany have increased significantly as both coal prices rose and high oil prices resulted in gas prices (oil and gas prices are linked, although both have significantly dropped lately). Furthermore this is due to a significant part of the opportunity costs of carbon being passed on to rate payers, leading to significant windfall profits for the power utilities[3]. Perhaps surprisingly, power utilities were not forced to repay these profits through windfall taxes. Given the long-term trajectory of further reductions on the carbon cap in Europe and the rapid movement towards full auctioning, the actual or opportunity costs will remain an integral part of the power price.

Given that power prices going forward are going to reflect carbon prices, there is little value in using pre-2005 power prices as a basis for the price distributions. The available and useful data sources for power prices are the daily power prices quoted by Bloomberg. Several prices are updated on a daily basis, including the day ahead, month ahead, and year ahead prices. The day ahead prices are very sensitive to sudden disruptions in power generation leading to very high price volatility; yet, they account for only a small part of the total power generation capacity. Instead, the forward month price was used as this price series correlates most closely with the monthly and quarterly commodity prices used is the analysis.

Having discussed the choices made for the main input variables to the investment model, the following two chapters will apply this model to differentiate the price effects and the allocation effects of carbon trading on investment decisions.

[3] The World Wildlife Fund (WWF) on a basis of several assumptions calculates that windfall profits in Germany alone in Phase II could reach 32.2 bn Euros. Sijm, Neuhoff and Chen (2006) estimate passed-through rates between 60%-100% for the German and Dutch markets.

5. Price Effects and Reconciling Fuel Spreads with Model Results

Having discussed the different inputs into the investment model, this chapter will discuss the price effects of emissions trading. In the second half of this chapter empirical fuel spread data will be introduced as a cross-reference for the model results presented in this thesis. These methods will be used to strengthen the point that the base case assumptions for gas, although initially compelling, might be too optimistic, which would explain the preference of coal investments as seen in the German market.

5.1 Price Effects of Carbon

Power plants are designed to either meet base or peaking capacity with the large, capital intensive investments suited for meeting baseload demand at high capacity factors. For the two investment options presented in this thesis, coal is dispatched as baseload, while the combined cycle gas power plant can be dispatched either for base- or for peakload; peak power prices are significantly higher to give an incentive for higher variable cost capacity to be deployed. There are several different power prices depending on the time to delivery, but these fundamentally reflect the costs of meeting marginal demand. Given that it becomes impossible to ramp up base capacity at minute's notice, the very short-term power prices are very volatile and can be very high to incentivized spinning reserve or flexible, but expensive, peaking plants to come to the market. Data quality varies significantly between European countries; for example, the Spanish market operator publishes the bids of the hourly electricity auctions, while in Germany only a daily value of base and peak power is reported on Bloomberg. Given the lack of dynamic pricing data, it is not possible to directly map the hourly dispatch data calculated from the bottom-up model to prices seen on the exchange.

The investment model calculates the distribution of returns and net present values as already elaborated in Chapter 4. Beginning with coal, the base case profitability is based on a capacity factor of 85% and base power pricing, since coal power plants are never dispatched for peaking capacity.

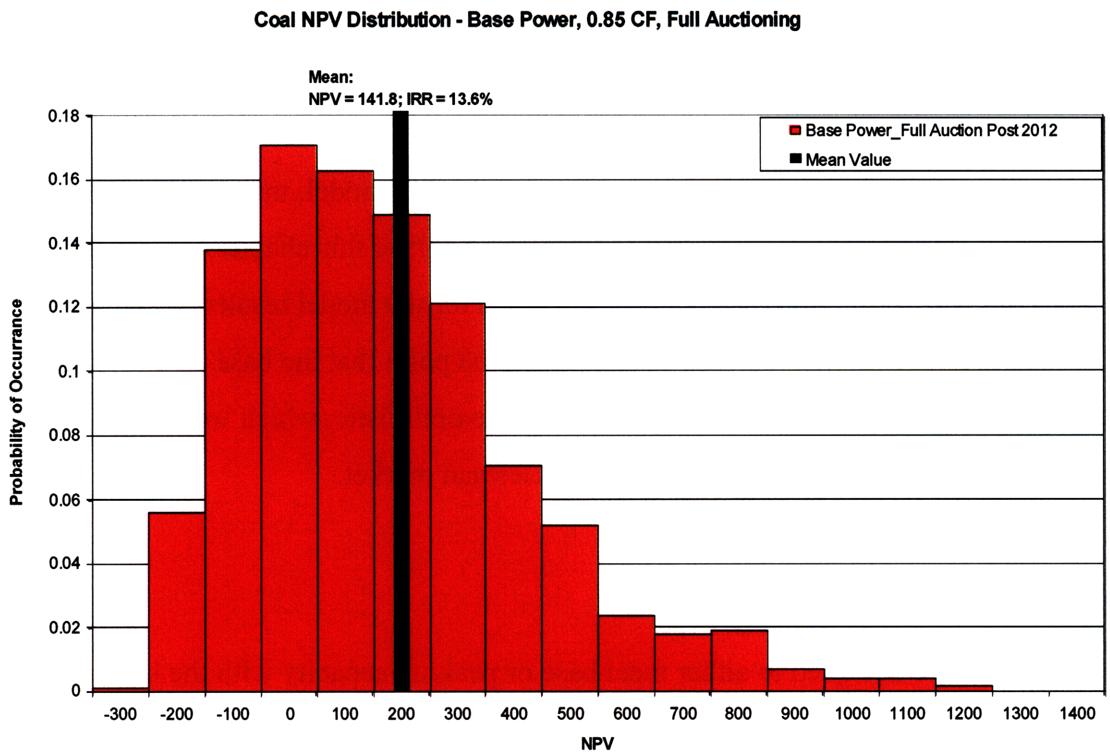


Figure 5.1: NPV distribution of Coal investment under base power pricing

Source: Model calculations

Assuming full auctioning for a coal plant, the NPV of the investment using power prices sampled from the base power price distribution has a mean of 141.81 million Euros with a mean IRR of 13.6%. The analysis shows that only with a probability of about 36.7% the investment results in negative returns; however it is important to note that very conservative assumptions have been made in choosing to use coal and carbon price samples and using only the total correlation of the entire sample set, rather than having the Monte Carlo simulation pick discrete pairs of carbon and coal prices actually observed historically. This results in price pairs of high carbon and low power prices being drawn that have not been observed in reality, but that are theoretically possible. Choosing only historically observed paired samples would reduce the tails of the distribution, providing more mass around the mean and make this distribution more leptokurtic. The following chapter will explore how different potential carbon allocation scenarios can increase the value of an investment in coal by shielding the cost impacts from carbon.

5.2. Gas Investment: Baseload versus Peak Dispatch

When looking at the combined cycle gas plant investments, there are two major assumptions one can make about the dispatch pattern. Either the gas plant can serve baseload demand, meaning that base power prices will be used and capacity factors that are equally high as for the coal plant (85% in the base case) are used. Otherwise, the gas plant can be dispatched to meet peak demand, which means that higher power prices are earned, yet the capacity factor is much lower (assumed at 40% in the base case).

As can be seen in the chart below, the outcome of these two scenarios shows that it is more profitable to have the plant meet peak demand, assuming that the capacity factor of 40% can be attained. The distributions and means of both gas plant setups are shown below. Furthermore a hybrid model between the two scenarios is likely. For example, given the seasonality of power demand with highest demand in the winter and lowest demand in the summer, the operator could decide to dispatch the gas plant to meet baseload demand during the winter months while dispatching the plant to meet peak demand in the summer months. This flexibility also gives the operator the opportunity to react flexibly to gas price volatilities.

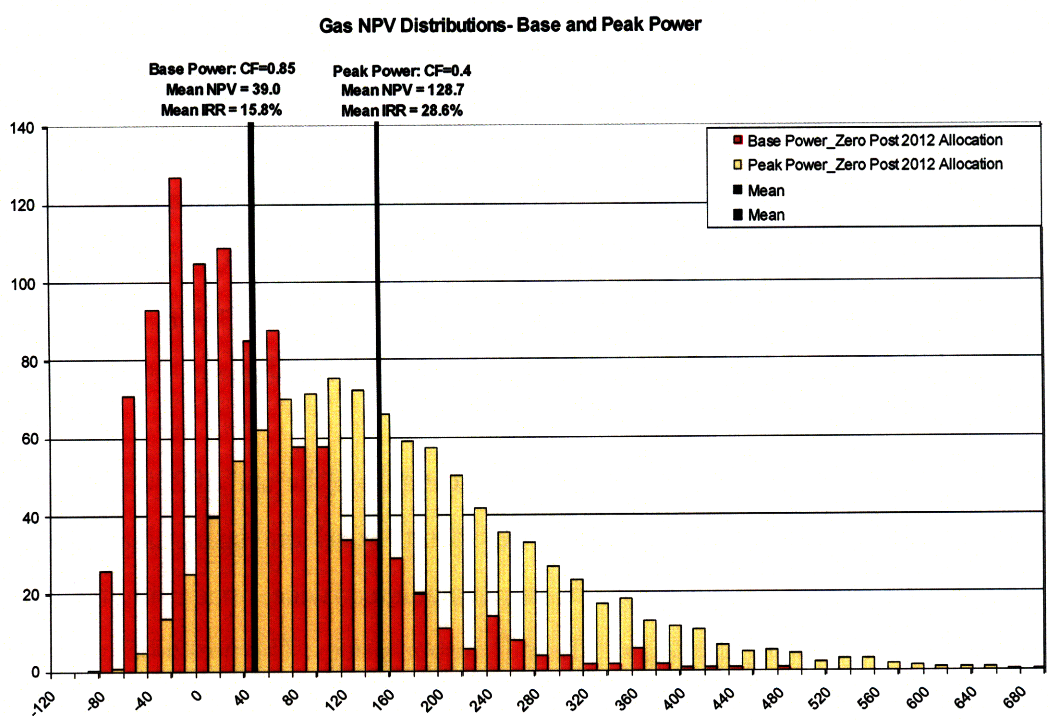


Figure 5.2: NPV distribution of Gas investment under baseload pricing and CF=85% as well as peak power pricing and CF=40%

Source: Model calculations

5.3. Spread Analysis- Reconciling Market Fuel Spreads and Model Results

One of the key analysis metrics used in the power industry are the spreads that a company is earning for generating power. These spreads make several simplifying assumptions on the production efficiencies of the power producing assets and take the heat rates of the fuels into account. The simple spreads only account for marginal costs and show the profit that is earned above the operating costs, i.e. the profits that will be retained to repay the capital costs. Positive spreads indicate that it is more profitable to generate power than to purchase the electricity from the market. For the analysis below API #2 coal prices, Zeebrugge European gas prices and the closest end-of-year carbon prices have been used.

There are several different spreads, each with a distinct name to specify its use:

a. (Dirty) Dark Spread- Refers to coal without adjustments for carbon
   = Power Price – (Coal Price/ Fuel efficiency)
b. Clean Dark Spread- Coal spreads adjusting for carbon prices
   = Dirty Dark Spread – (CO_2 intensity of coal*CO_2 price)
c. (Dirty) Spark Spread- Refers to natural gas without carbon adjustment
   = Power Price – (Gas Price/ Fuel efficiency)
d. Clean Spark Spread- Gas spreads adjusting for carbon prices
   = Dirty Spark Spread – (CO_2 intensity of gas*CO_2 price)

These spreads are quoted on Bloomberg, however, there is only very limited historic data available for these spreads. Hence, the spreads were recreated from first principles using long-dated price series. While the absolute value of the spreads is interesting, the real question for making a relative investment decision between coal and gas is the movement of the difference of the dark and spark spreads.

The figure below gives a long-time series of these spreads from the end of 2000 until February 2009. The figure shows the difference between the dark and spark clean spreads (i.e. carbon-price adjusted). The clean spreads were calculated twice, once using the spot price for carbon and once using the higher Phase II carbon prices. The pre-2005 carbon price obviously is zero, however, later in this chapter two scenarios will show these fuel spreads if a carbon price of 8 or 15 Euros per ton is assumed for the years 2000-2004. The difference between the spot and Phase II fuel spread charts below emerges in late 2006 and 2007 when the Phase I carbon price tended to zero while the contract with

December 2008 delivery did not move significantly. Obviously, using the higher Phase II price favors gas since it has a lower carbon intensity, although the overall difference is not very large and is not explicitly shown in the figure below. Using this analysis it becomes possible to count the number of days when the clean dark spread (coal-based) is above the clean spark spread (gas-based) to see how many days coal dominates gas a more profitable fuel.

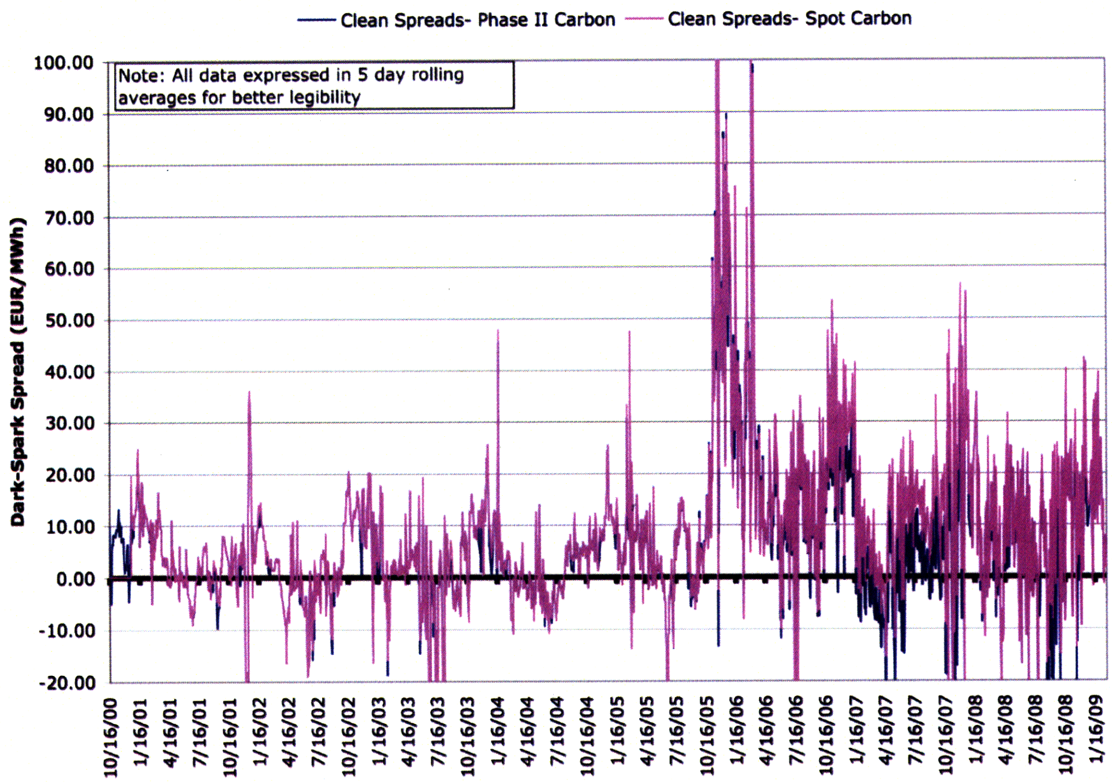


Figure 5.3: Clean Spreads for Coal and Gas from 2000-2009

Source: Bloomberg, ECX, model calculations

Table 5.1: Spread Analysis

	Clean Spreads using Phase II Carbon	Clean Spreads and Spot Carbon	
	2005-2008	2005-2008	2000-2004
Days with Positive Spread	707	745	617
Total Days with Data	969	914	939
Fraction Coal Dominance	**72.96%**	**81.51%**	**65.71%**

Source: Model calculations

The outcome is striking. The large majority of days show a higher profitability of coal plants versus gas plants. The data is presented as five day rolling averages to smooth the data, in order to make it more easily legible on a graph with a long time series, although the calculations have not been smoothed.
Another very interesting feature emerges when taking a closer look at the data. There are clearly seasonal effects of commodity prices that can be seen in the data; the dark-spark spread is lower during the summer months, coinciding with the seasonal dip in gas prices often turning negative, which serves as an indicator to operate a gas plant. Moreover, the absolute value of the spread difference indicates that coal plant investments have actually become *more* profitable versus gas since the introduction of carbon emissions trading; this is a slightly counter-intuitive result but with great explanatory power for the recent announcements of new coal builds, as outlined in Chapter 3 of the thesis. While in the time before carbon emissions trading, it was more profitable to operate coal power plants versus gas plants on 65.7% of trading days. During the emissions trading scheme this increased to 81.5% of trading days, showing a clear preference for coal over gas and exemplifying the coal/gas fuel price ratio increasing.

5.4. Cost Pass-Through

An implicit assumption made in all the spread calculations so far is that the carbon price is passed on in full to the power price and hence the consumer. Reinaud (2004) discusses the distorting effects that partial cost pass-through effects could have on the EU-ETS sectors including the power sector. Sijm, Neuhoff, Chen, 2006 find evidence of carbon cost pass-through between 60%-80% in Phase I for power installations that received free allocations. One of the central arguments for auctioning is that the pass-through of the carbon price will be reflected in consumer choice reacting to these higher prices. The sensitivity analysis below shows the impacts on the base case profitability of the power and gas investments, assuming baseload dispatch for coal and peak dispatch for gas. This is done by subtracting the CO2 cost element from the power price, which is deducting the carbon coal CO2 costs from the base load price or deducting the gas CO2 costs from the peak power price. In the case of full (100%) pass through, the companies fully pass on the carbon price through the power price charged to the consumer. In the scenario of 125% pass-through, the power prices are increased by 25% of the carbon price, if the utilities were to theoretically charge the consumer beyond the actual carbon cost incurred, which is a situation sometimes seen in monopolies. The table shows how large the impact of the carbon price is on the profitability of coal investments relative to gas investments and is a reflection how geared the coal investment is towards the carbon price.

Table 5.2: Cost Pass-Through effects on coal and gas plants

Pass-Through	Coal NPV-Base	Gas NPV-Peak	Coal-NPV/Equity	Gas-NPV/Equity
75%	-40.2	116.3	-0.2	2.3
100%	**141.8**	**128.7**	**0.7**	**2.6**
125%	259.2	139.3	1.3	2.8

Assumptions	*Capacity (MW)*	*Plant Life (years)*	*Equity Invested (mn EUR)*	*Pricing*	*CF*
Coal	*500*	*40*	*192.1*	*Base*	*0.85*
Gas	*300*	*25*	*49.596*	*Peak*	*0.4*

Source: Model Calculations

Adjustments for Capital Cost:

The analysis so far has not taken into account the capital cost, looking only at the marginal operating cost. In the investment model, the capital cost is reflected through the constant annual loan repayment charge on the debt, which both pays debt interest and principal. In the base case of the model, a debt level of 60% is assumed. The capital cost for a gas plant are assumed at 0.41 million EUR/ MW of capacity while the costs for a coal fired plant are more than twice that level at 0.96 million EUR/MW capacity. To attain a cost per output, the annual debt service charge is divided by the amount of energy generated. The energy output of the plant is highly dependent on the capacity factor and increases linearly with a decrease in the capacity factor, since the capital charges need to be recovered over fewer units of output. The table below shows the resulting capital cost charges for a number of capacity factors, while the model calculations use 85% as a base case scenario.

Table 5.3: Capital costs and capacity factors

Capital Cost Per Technology		
Capacity Factor	Coal (EUR/MWh)	Gas (EUR/MWh)
85%	2.03	1.01
80%	2.16	1.07
70%	2.47	1.22
60%	2.88	1.43
50%	3.46	1.71
40%	4.32	2.14

Source: Model calculations

The fuel spreads shown above in figure 5.3 are thus the main measure for the investment profitability excluding capital cost. Hence, to adjust the fuel spreads for the capital cost the difference in clean fuel spreads must be 1.02 EUR/MWh or higher for coal to be more profitable than gas (assuming a capacity factor of 85%, where the 1.02 EUR/MWh is the difference between the capital cost for coal of 2.03 EUR/MWh and gas of 1.01 EUR/MWh). Adjusting for capital costs still leaves coal the more profitable fuel in more than 78% of days over the last four years, assuming spot carbon prices or almost 70% of days when applying Phase II carbon prices.

Table 5.4: Capital adjusted spreads

	Clean Spreads using Phase II Carbon	Clean Spreads and Spot Carbon	
	2005-2008	2005-2008	2000-2004
Days with Positive Spread	707	745	617
Total Days with Data	969	914	939
Fraction Coal Dominance	72.96%	81.51%	65.71%
Fraction Coal Dominance-Capital Cost Adjusted	69.45%	78.34%	58.25%

Source: Model calculations

Looking at these numbers it seems counter-intuitive why anyone would argue for the construction of gas-fired power plants at any point back to the year 2000, when large amounts of gas-fired capacity were built. However, adjusting the pre-2005 figures for the carbon prices at levels that had been anticipated prior to the start of the EU-ETS, it becomes apparent why a strong argument for gas existed. This is visualized in the graph below that shows in blue the pre-Phase I 2000-2004 spreads with no carbon price; all data is shown as a 50 day moving average for better legibility. The straight line is the trend line and shows that on average it is more profitable to burn coal over the entire time period. The magenta line assumes an 8 Euro per ton carbon price being added between 2000 and 2004. This shifts the trend line by about 4 Euros, showing a preference for gas on average over the entire period. If the hypothetical carbon price is increased to 15 Euros per ton to the 2000-2004 fuel spreads (shown in green), an even clearer preference for gas over the entire period emerges. Hence assuming a hypothetical carbon price for the years 2000-2004 results in a vertical move of the spreads of about four Euros if a carbon price of 8 Euros/ton is assumed and seven Euros for a carbon price of 15 Euros/ton compared to the baseline of no carbon price.

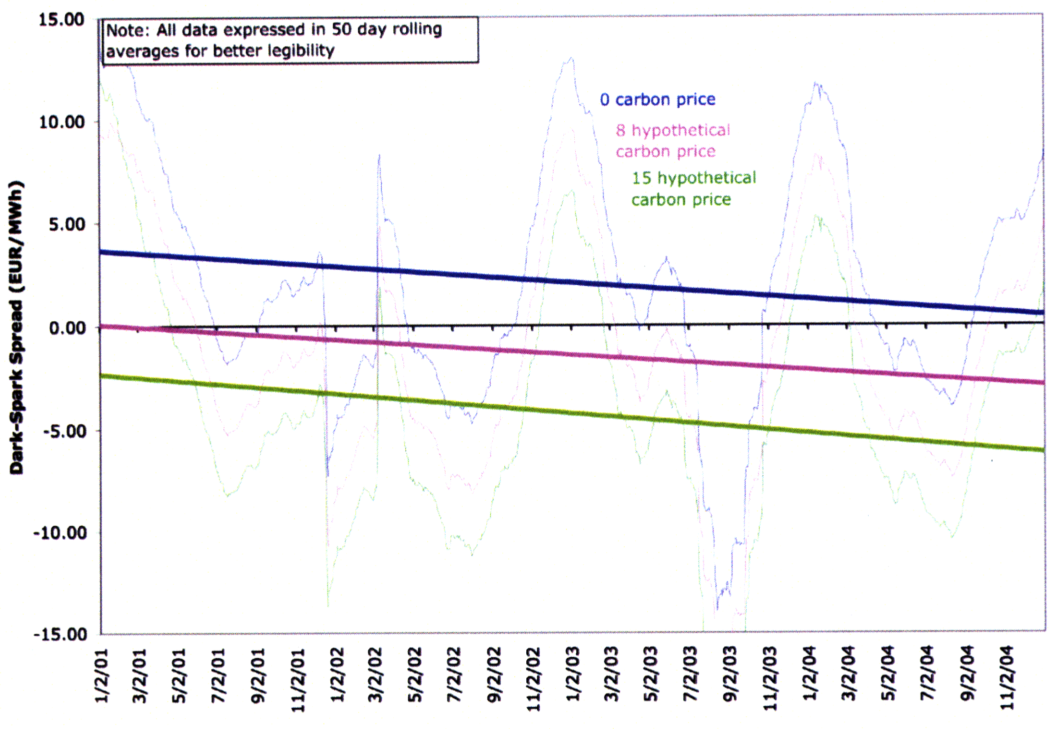


Figure 5.4: Pre-Phase I spreads showing effect of hypothetical carbon prices

Source: Bloomberg data and author calculations

Table 5.5: Clean Spreads using spot prices for carbon

	Clean Spreads using Phase II Carbon	Clean Spreads and Spot Carbon		2000-2004 with Hypothetical Carbon Prices	
	2005-2008	2005-2008	2000-2004	8 EUR	15 EUR
Days with Positive Spread	707	745	617	406	260
Total Days with Data	969	914	939	939	939
Fraction Coal Dominance	**72.96%**	**81.51%**	**65.71%**	**43.24%**	**27.69%**
Fraction Coal Dominance-Capital Cost Adjusted	**69.45%**	**78.34%**	**58.25%**	**36.53%**	**24.07%**

Source: Model calculations

With a hypothetical carbon price of 8 Euros, the number of days prior to Phase I, when coal was more profitable, is reduced to 43% or 37% when adjusting for capital cost, assuming a capacity factor of 85%. Moreover, when adding a hypothetical carbon price, the number of days when coal is the dominant fuel further falls to 28% or 24% when adjusting for capital cost. This makes a very compelling argument for building gas plants, even when assuming that gas plants will be dispatched only when fuel spreads are favorable for gas.

Looking at these results and assuming a Phase II carbon price, the number of days when coal is the more profitable fuel is reduced from 82% to 73%. However, given that historically the pass-through rates of the carbon prices into the power price are very high, the actual power price would likely be higher in an environment of elevated carbon prices, and this would marginally benefit coal which has lower marginal costs. Such results explain the preference for gas fired investments in the run-up to the EU-ETS, while the Phase I numbers also explain the recent preference for coal-fired investments. Overall, this analysis shows how large fluctuations in fuel prices dominate any moderate changes in the carbon price.

Using these figures as more realistic capacity factors for the investment model, it becomes clear why the preference for new investments is coal and not natural gas.
The table compares the initial base case assumptions from the analysis with the updated capacity factors based on the spread analysis. The analysis shows the preference for a

coal in a baseload dispatch (IRR = 13.6%; NPV/equity = 0.74) over gas in a peak dispatch, if the capacity factor is reduced to 0.25 (IRR = 11.1%; NPV/equity = 0.31), as well as gas in a baseload dispatch, if the capacity factor is reduced to 0.8 (IRR = 13.3%; NPV/equity = 0.54).

Table 5.6: Capacity Factor Sensitivity Analysis

	Coal	Gas- Base			Gas- Peak			
Capacity Factor	**0.85**	**0.85**	**0.8**		**0.4**	**0.35**	**0.3**	**0.25**
NPV	141.8	38.9	26.6		128.7	92.5	53.89	15.27
NPV/MW	0.28	0.13	0.09		0.43	0.31	0.18	0.05
NPV/Equity	0.74	0.78	0.54		2.59	1.87	1.09	0.31
IRR	**13.6%**	**15.8%**	**13.3%**		**28.6%**	**23.4%**	**17.4%**	**11.1%**

Capacity	*500*	*300*
Equity	*192.1*	*49.596*

Source: Model Calculations

The case for showing the strong effect of fundamental fuel prices is furthermore exemplified when looking across the commodity price distributions and calculating the carbon price required to equalize short run marginal costs. The figure shows the components of the marginal price, namely fuel costs, variable O&M costs, as well as carbon costs in dark gray. The resulting carbon price that would equalize the operating costs is the solid line that is traced onto the secondary Y-axis on the right. The above figure splits the price distributions for gas and coal into deciles on the X-axis in opposite directions; the lowest 10% of gas prices are being shown at the left together with the highest 10% of coal prices. This gives an overview of the most extreme values that the carbon price can take, i.e. the lowest possible gas price paired with the highest possible coal price moving to the highest possible gas price and the lowest possible coal price. Historically, gas and coal prices have slightly correlated (R squared of 0.13), making the extreme cases highly unlikely. The figure shows that a carbon price would need to rise above 100 Euros/ton in order to give an economic incentive for fuel switching, if gas prices are above their 70^{th} percentile and coal prices are in their lowest 30^{th} percentile. The table shows, for example, that if gas prices being in their lowest 30^{th} percentile and coal prices in their 70^{th} percentile, a carbon price of 28 Euros/ton would exactly equalize the short-term variable costs of both plants and give rise to fuel switching on the margin.

The analysis furthermore shows that if gas prices are in their lowest 20th percentile, fuel switching will always occur (if there is sufficient spare capacity in the system) as seen by the negative resulting carbon prices.

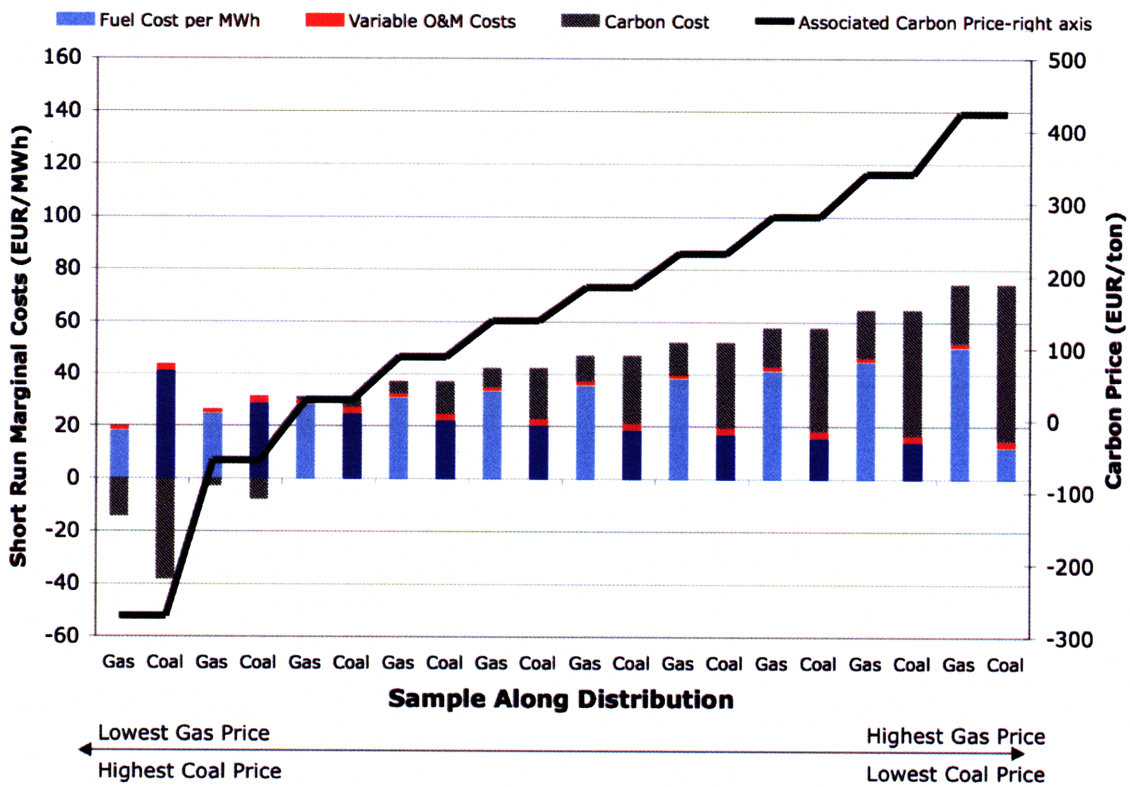


Figure 5.5: Commodity Price Distributions and related carbon prices

Source: Model Calculations

Thus the price effects show that fuel prices can dominate carbon price effects and, furthermore, that only a combination of both effects provides the full explanation of technology choice. In addition to the price effects of carbon there are also allocation effects that will be discussed in the following chapter.

6. Allocation Effects

Having introduced the investment model and the price effects seen from carbon, this chapter will provide a framework for quantifying the impact of allocation effects on coal and gas investments. The investment model will be used to exemplify, how policy can change the value of generation projects and can affect the choice between coal and gas fired power plants. Furthermore, fuel spread analysis will be used to explain why coal investments in Germany are clearly favorable under significant free allocations. Gas investments are more profitable in a full auctioning scenario assuming high capacity factors, which are currently not seen in the market, though. Hence, full auctioning provides an incentive to lower the power sector's emissions intensity while free allocations will clearly favor coal investments. All these effects can, however, be dominated by fuel price effects as will be shown in this chapter. After Chapter 2 had looked more closely on the short-term effects from fuel switching driven mainly by marginal cost, this chapter relates to new generation assets, where both operating and upfront capital costs have to be taken into account.

6.1. National Allocation Plans and Methods of Setting the Cap

There are several possibilities for disbursing carbon emissions permits within a cap and trade system. The two most widely used mechanisms are free allocation (also known as grandfathering) and auctioning of these rights. Several hybrid mechanisms exist, for example, auctioning a proportion of the credits while grandfathering other portions of the total cap. A third mechanism of allocation is to create a sector-specific or technology-specific benchmark that allocates credits according to a specific carbon intensity (tons/ MWh generated); any credits required above this benchmark would need to be purchased in the free market. This chapter will discuss the impacts of such provisions, while also quantifying the impact of so-called new entrant and closure rules that were initially part of drafts for the German National allocation plans but have now been removed for any new investments in generation assets.

6.1.1 Grandfathering

Phase I of the EU-ETS (2005-2007) made almost exclusive use of grandfathering as an allocation mechanism where carbon credits were allocated at zero cost based on historic emissions. Boehringer (2005) provides a formal analysis of optimal allocation using grandfathering. In Germany installations were grandfathered 97.09% of baseline emissions, a total amount that turned out to be higher than actual emissions, hence driving the carbon price to transaction cost levels in the Euro cent range towards the end of Phase I in 2007. In the second phase of the EU-ETS, power installations were allocated 85% of historic baseline emissions. The European Council decided in December 2008 that the power sector will move to full auctioning in Phase III with limited exceptions. Firstly, national allocation plans will be substituted with a central allocation mechanism that greatly harmonizes overall allocation and rules out any special provisions, such as the German ex-post adjustment that had been used in the first trading phase. Secondly, grandfathering to the power sector will be replaced by full auctioning of emissions permit "taking into account their ability to pass on the increased cost of CO2" (EC Commission, 2008). The European Commission treats the energy intensive industries differently, since they stand in international competition in often highly commoditized markets with very slim margins. Hence, the EU Commission foresees grandfathering to being reduced to 30% by 2020 with a complete phase out aimed by 2027 (European Parliament, 2008).

6.1.2 Auctioning

In the first phase of the EU-ETS, auctioning was hardly used. The EU Commission allowed national governments to auction up to 5% of the cap and 10% in the current Phase II. In Phase I, only four member states auctioned emissions credits amounting to a total of 0.13% of the total allocation. The use of auctioning in the second phase is higher, but the total volume is far below the potential volume of 10% of EU-ETS wide emissions. As stated in the amended EU Emissions Trading Directive (EC 2008A), full auctioning in the power sector is encouraged from 2013. Transitional free allocation for modernization of electricity generation can be granted to countries with weak integration into the network interconnected system, where in 2006, 30% of electricity was produced from a single fossil fuel or where the 2006 gross domestic product per capita at market prices did not exceed 50% of the average gross domestic product per capita of the EU (ibid).

Auction theory constitutes a large field in applied economics and a thorough treatment of the topic would go beyond the scope of this thesis. For an in-depth discussion of auctioning experiences from different sectors, Klemperer (2002) or Jensen (2004) can be referred to. The seminal report by Matthes and Neuhoff (2007) expands on the different auction design aspects,too, and can also be applied specifically to the EU-ETS with its concrete recommendations. A short overview of their ten main design parameters and recommendations is provided in this table below:

Table 6.1: Design Variables and recommendations for auctions

Design Variable	**Matthes and Neuhoff Recommendation**
1. Participants	All entities with registry account; have financial players to provide liquidity
2. Number of Rounds	Single round simple; no need for revealed preference in multi-round auction, secondary market prices indicate demand
3. Clearing Price Calculation	Simple uniform price auction for simplicity and participation of unsophisticated bidders
4. Auction Frequency	At least monthly, best weekly
5. Allowance Distribution across auctions	Transparent and consistent application of procedure and taking into account hedging demand. Explicit statement if low price is politically unwanted
6. Reserve Price	Using reserve price close to previous trading day increases transparency and protects integrity from unexpected outcomes due to technical failures
7. Margin Payments	Credit posting of e.g. 10% of bid value to reduce counterparty risk and ensure seriousness of bids
8. Auction Host	Find institution already operating in similar business
9. Bid Restriction	No restriction on bids, but limit bids to certain share number of allowances
10. Monitoring and Transparency	Market monitoring similar to other commodity markets with regular publication of aggregate data.

Source: Matthes and Neuhoff (2007)

Reflecting auctioning the investment decision model

Auctioning impacts the absolute and relative profitability of power generation investments by adding a cash cost of carbon emissions credits to the operating costs of the power plants. Given that coal plants have higher carbon intensities than gas plants, the impact of auctioning on coal investments is higher than those for gas. Several scenarios quantify the differences between auctioning and grandfathering; these are shown later in this chapter.

Assuming the Phase III provisions remain in place as they currently stand, the cash cost of auctioning to the power plant operator will be significant. The underlying assumption is that auction will not impact the carbon price and hence the original price distribution is used in the model. Furthermore, this approach assumes that the price that power companies have to pay in the auctions will be the average price of the rights in the secondary market, i.e. that prices will not be artificially high or low from arbitrage between the auctioning and secondary markets.

6.1.3 Benchmark

An alternative allocation mechanism to grandfathering and auctioning is to allocate emission certificates base on benchmarks. Benchmarks define a set emissions intensity and define a cap by multiplying the benchmark intensity with a variable that describes the output or size of the industrial operation. The actual benchmark can be set in accordance with various measures and is often done with the "best available technology" (BAT) to give companies an incentive to invest in modern and low-emission intensity capital equipment. In practice, several characteristics can be used as the basis for a benchmark allocation, as described by Matthes and Neuhoff (2007) including:

1. Historic production using a fixed baseline
2. Historic production using a moving baseline
3. Current production
4. Projected production using some model-based approach
5. Installed capacity

One of the main areas where benchmarks have been used is in the calculation of new entrant allocations. The use of benchmarks can become very difficult to administer in an equitable fashion, especially in highly heterogeneous industries; in the power sector the most widely used benchmarks are either based on installed capacity or power output.

6.2 Impact of New Entrant Rules

One special characteristic of the EU ETS is the set of rules surrounding the treatment of new entrants. The 2003 emissions trading directive of the European Commission (2003/87/EC), for instance, allows for the allocation of free allowances to incumbents that build new capacity. Article 3h of the directive defines a new entrant as an installation, "which has obtained a greenhouse gas emissions permit or an update of its greenhouse gas emissions permit because of a change in the nature or functioning or an extension of the installations, subsequent to the notification to the Commission of the national allocation plan". Furthermore, the national allocation plans need to disclose the amount of new entrants that are granted to generating companies. In the first phase of the EU-ETS, free allocations to new entrants were granted in all participants of the EU-ETS, expect for Sweden where new entrant allocations were only granted to very efficient CHP plants and industry. The reserve size as a fraction of the total cap varied substantially between countries from 0.4% in Poland to 16.7% in Italy. Most countries allocated emissions based on best available technology standards (BAT). However, there are several different ways of allocating new entrant allocations, which are classified by Åhman and Holmgren 2006:

1. ***Input- or Output Based-*** Using a pre-determined benchmark of carbon credits is multiplied either by the input factor, such as capacity, or the output factor, such as emissions or power generated. Output based benchmarks are usually preferred since they incentivizes efficient energy generation.

2. ***Fuel-neutral or Fuel-specific-*** Using different benchmarks by fuel gives an incentive to use low-carbon fuels, however, they tend to not encourage investments in low-carbon fuels.

3. ***Technology-neutral or Technology-specific-*** Technology-specific benchmarks are used mostly to promote specific technologies or to accommodate for the different conditions in which different technologies are used. Technology-specific benchmarks have little justification for incentivizing least-cost emissions reductions.

4. ***Product-specific or Product-neutral-*** In this case the product applies to electricity or heat, and separating these two enables for a harmonization of electricity incentives (which is easily transportable and tradable across borders) versus heat which by its fundamental properties is a local product.

Table 6.2: New Entrants in the First Phase of the EU-ETS

Country	NER	Reserve size as percentage of total cap	Allowance withdrawn upon closure	Allocation metric for new entrants
Austria	Yes	1.8	Yes	BAT
Belgium	Yes	4.0	Yes	BAT
Cyprus	Yes	0.7	no information	BAT
Czech Republic	Yes	3.1	Yes	BAT
Denmark	Yes	3.0	Yes	BAT
Estonia	Yes	3.4	no information	BAT
Finland	Yes	1.8	Yes	BAT
France	Yes	1.7	Yes	Average
Germany	Yes	0.6	Yes	BAT
Greece	Yes	4.3	Yes	As needed
Hungary	Yes	1.9	Yes	BAT
Ireland	Yes	1.5	Yes	BAT
Italy	Yes	16.7	Yes	BAT
Latvia	Yes	11.5	no information	As needed
Lithuania	Yes	5.0	no information	Benchmark
Luxemburg	Yes	12.0	Yes	BAT
Malta	Yes	26.3	no information	BAT
Netherlands	Yes	2.6	No	BAT
Poland	Yes	0.4	no information	BAT
Portugal	Yes	8.0	Yes	BAT
Slovakia	Yes	2.3	no information	BAT
Slovenia	Yes	0.8	Yes	BAT
Spain	Yes	3.6	Yes	BAT
Sweden	CHP/industry only	3.2	No	BAT
United Kingdom	Yes	6.3	Yes	BAT

Source: DEHSt, 2005

The somewhat technical issue of allocation evolved into a much larger debate of market power, competitiveness and innovation.

Fundamental economic principles suggest that new entrants should not be allocated with allowances free of charge, since the investment decision should reflect the cost of the carbon emissions. Free allocations are thus only provided to compensate current installations for the investment sunk costs made before the ETS came into action and that are now less profitable in a world that prices carbon (see Harrison and Radov, 2002). EU member states applied new entrant allocations stating it would be useful for competitiveness. For example, the large power incumbents could effectively subsidize their new entrant capacity by reducing the output from the existing fleet or even closing marginal plants and using the allocation for that capacity for the new entrants (Neuhoff et al, 2006). Hence, the new entrant rule was seen a means to reduce any potential barriers to entry that the EU-ETS could implicitly create, especially towards small, independent power companies entering into the oligopolistic market structure (Reinaud 2005). The market power argument was first made by Hinchy (1998) in looking at the distortions that allocation effects can have on the market; incumbents could shield their dominant position by increasing transaction cost, squeezing new entrants out of the market using predatory pricing and using the existing generation assets with grandfathered carbon credits to cross-subsidize new entrant capacity. Betz (2003) challenges the assumed magnitude of the transaction cost increases, but he in principle agrees with the arguments made.

Lambie (2002) also draws attention to the financing consequences of large incumbents versus small new entrants. Capital markets - especially in the current illiquid and constrained conditions – tend to favor incumbent players with stable cash flows, higher debt capacities and higher debt/equity ratios. These have access to cheaper cost of capital, compared to the smaller entrants that will have to rely more heavily on equity financing and thus face a higher project hurdle rate. Gagelmann (2006) quotes Allen Consulting in reporting that opportunity costs considerations can become irrelevant, if large incumbents are in public ownership and political interests dominate investment decisions. Furthermore, investment decisions could be driven by average costs rather than marginal costs in an environment of price controls, which is highly prevalent, for example, in the United States regulated utility areas, but is less applicable to European power markets that have undergone significant deregulation recently.

Furthermore, new entrant allocations can have a real option effect on first investment decisions. Following the framework of real options analysis presented by Trigeorgis (1995) and de Neufville (2003), an incumbent power producer would give up the value of future allocations by closing a plant. Especially in an environment of high carbon price volatility, the option value of waiting increases, which leads to slower asset turnaround and – assuming technological innovation from new investments- slower technical progress to a lower emissions trajectory generation fleet.

Incentives and innovation effects

While there are distinct economic effects from differing allocation mechanisms, part of the literature has also focused on the consequences of new entrant allocations on incentives and innovations. Ashford (2002) focuses on new entrants as drivers of new innovations and more generally on industries with rapid market entry and higher competition that foster an environment where differentiation through innovation is incentivized. Contrary to the inertial effects of new entrant allocations, these credits can also raise the incentives for market entry which leads to increased production capacity, although as Ellerman (2006) clarifies this investment subsidy and its effects change dynamically with the level of the allowance price and are not a fixed amount.

Empirical evidence from other environmental markets

The debate over the efficiency and effectiveness of new entrant allocations has also occurred in previous environmental markets. The United States, which was one of the driving forces in the establishment of environmental markets, has several examples. There the allocations have tended to favor a fixed allocation, often with a large front-loading of allocations into emissions banks. A single allocation without new entrant allocations is economically efficient as long as no substantial leakage effects, capital constraints, or dominant market positions exist; all these assumptions cannot be found to hold entirely in the EU-ETS. Harrison and Radov (2002) give a concise overview of several key US emissions trading schemes, highlighting key system design variables such as allocation method, metrics, and allocation length, an excerpt of which is reproduced below:

Table 6.3: Allocation and Metrics in US Emissions Markets

Program	Allocation Method			Metrics			Allocation Year	Recipients
	Auction	Grand-father	Update	Input-based	Production-based	Emissions-based		
US SO2	X	X		X			3-year average	Existing emitters. Set-aside for efficiency and renewables
California RECLAIM (SOx, NOx)		X			X		Max out of 4 years	Existing emitters. Additional allocation for early action
US OTC NOx		X				X	1 year	States covered under the OTC
US ODS Phase-out		X			X	X	1 year	Existing emitters

Source: Harrison, Radov, 2002

Closure Provisions

Several countries, including Germany, made use of a closure provision which states that power plants that were operated at levels <60% had to be closed, and the allocation for these assets would have to be surrendered to the national authorities. This, however, creates perverse incentives to continue the operation of inefficient and thus very carbon intensive power plants, as discussed succinctly in Ellerman (2006). Matthes and Neuhoff (2007) argue that the costs of closure of inefficient plants leads firms to continue running their existing portfolio. This could be avoided by transfer rules that were also implemented by member states and the European Commission. In Germany, for example, operators that closed old installations may have "old" allowance transferred to other installations that are still running (ZuG 2007). Schleich and Cremer (2007) argue that the degree of the disincentive to invest created by closure rules depends on the amount of allowances that the company forgoes due to closure. They find that closure rules combined with grandfathering provides a large disincentive for investment in more efficient technologies, while closure rules combined with BAT-based allocation would incentivize closure of high carbon intensity assets. Furthermore, Cames (2007) discusses the negative impact on innovation from the continued use of older assets, resulting in a higher plant age and lower efficiency.

6.3 New Entrants in Germany: Quantifying Profitability Impacts of Policy Change

The effects of new entrants and other design factors introduced within the NAP I have been analyzed comprehensively by authors such as Ellerman (2006), Matthes et al. (2005) and Ecofys (2004). The policy surrounding new entrants has undergone several significant changes all of which are accompanied by impacts on the profitability of current and future investments. Using the investment model, this part of the thesis will aim to quantify the profitability impacts of the policy changes. Ahman and Holmgren (2006) have used quantitative analysis of the value of new entrant allocation relative to capital and operating costs of coal and gas plants as an argument against new entrant allocation. They show that the significant value bestowed in new entrant allocations can significantly distort competition. Rather than draw conclusions on the competitive effects, this analysis aims to show, how a change in new entrant allocation policy alters the relative economics of new power plant investments. These results will be assessed as to how far they contradict or help explain the investment behavior observed in the European Union and especially in Germany.

New entrant allocations have undergone several policy changes within the German NAPs. The first phase of the ETS allowed for 100% free allocation of new entrants. The condition attached to this free allocation was that the new builds had to fulfill a minimum technology standard (best available technology or BAT). Specifically, this meant that a new build that began operations after January 1, 2005 would receive up to 0.750 EUA per kWh and at least 0.365 EUA per kWh for gas powered stations. In the first emissions trading phase, there was the so-called "ex-post" adjustment of emissions allocations, which was implemented to prevent power stations from reducing output of power stations while still receiving the free allocation. Under the ex-post adjustment the allocations for any power plants would be taken away if the power plants would have been run less than 60% of the average run rate during the basis period. This clause was highly contentious within the EU Commission and was taken out for the second phase of emissions trading. The real value from the new entrant allocation, however, came from the provision guaranteeing 14 years of full, free allocation.

Changes between Phase I and Phase II included the abolishment of the German 14 year allocation rule and the reduction of power sector free allocation from 97.09% to 85% of basis period emissions. The new entrant reserve was significantly increased from 3 million tons annually in Phase I to 17 million tons in Phase II.[4]

Table 6.4: Changes of Allocation mechanisms across phases

Time	Phase I (2005-07)	Phase II (2008-12)	Phase III (2012-20)
Legislative Basis:	NAP I	NAP II	Directive 2003/87/EC amendment of Jan. 2008, Council Decision Dec. 08
Power Sector Cap:	97.09% of basis period emissions	85% of basis period emissions	Full auction for Germany
New Entrants:	100% free allocation for BAT plants; ex-post adjustment	100% free allocation for BAT plants, if plants run above 60%	"no free allocation should be made in respect of the production of electricity by new entrants"
New Entrant Guarantee:	14 years full allocation, no digression	Abolished	Abolished
New Entrant Reserve:	3 mn tons annually	17 mn tons annually	None

Source: BMU 2007, EU Commission 2008

The December 2008 European Council Decision clarified the Phase III outlook. Free allocation to the power sector is abolished with limited exceptions, mostly for recent EU accession states. The EU Commission justifies the move towards auctioning with concerns over distortions of competition in the European power markets. At the same time the Commission grants Eastern European power industries and industrials continuing free allocations on the basis of relative wealth and global competitiveness of the markets the companies operate in.

[4] The 17mn tons annual Phase II new entrant reserve includes 5 mn tons per year to replenish the depleted reserves from Phase I.

This policy change has large impacts on the profitability of power investments in that a large subsidy to operating costs has been removed. The supporting documentation of the Emissions Trading Directive is relatively clear on the intention to abolish new entrant allocations and move towards a market of full auctioning with no free allocation (EU Commission 2008 B). Using the power investment model, three distinct scenarios are modeled, all assuming baseload power pricing. All scenarios assume new build and take into account the investment effects, rather than considering only marginal costs of existing plants.

Scenario 1: Business as Usual from NAP I with NER

The BAT limits set for power plants are upheld and 14 year free allocations are granted from the first year of operation onwards. Rather than showing this as a likely scenario, it is used to show the conditions faced by German utilities towards the end of Phase I.

Scenario 2: Business as usual from NAP II is phased out linearly over Phase III

This is an intermediate scenario where the full allocation is held until 2012 and then phased out over the 8 years of Phase III, when the percentage of total emissions that needs to be purchased increases linearly per year. This scenario is more stringent than free allocation, but less stringent than full auctioning.

Scenario 3: New entrant provision abolished; full auctioning from 2013 onwards

This scenario is in line with the current EU Council decision on Phase III emissions trading. Of the three scenarios, it is the most stringent and results in the lowest mean net present value of the investments.

Hence, this analysis can quantify the impact of different allocation mechanisms on power plant profitability. The IRR figures shown below pertain to the returns earned on the project cash flows and assume that cash flows can be reinvested at the exact same rates of return over the entire lifetime of the investment; hence, the IRR figure is likely to be higher than the actual returns observed in reality over the entire project life cycle. The raw net present values are not comparable, since they are based on plants of different sizes (capacities), life times and capital costs. Hence they are normalized by the net present value per million EUR of equity investment to better reflect the value to the equity investor.

Table 6.5: Summary of Allocation Effects

Scenario:	**Full Auctioning (Scenario 3)**	**Free allocation phase-out (Scenario 2)**	**New Entrant Allocation (Scenario 1)**
Coal NPV (mn EUR)	141.81	249.54	578.05
Coal NPV/MW (mn EUR/MW capacity)	0.28	0.50	1.16
Coal NPV/Equity investment (mn EUR/ mn EUR)	**0.74**	**1.30**	**3.01**
Coal IRR; CF=0.85	**13.60%**	**20.50%**	**32.20%**
Gas_Base NPV (mn EUR)	38.99	69.19	132.36
Gas_Base NPV/MW (mn EUR/MW capacity)	0.13	0.23	0.44
Gas_Base NPV/Equity investment	**0.79**	**1.40**	**2.67**
Gas_Base IRR; CF=0.85	**15.80%**	**22.90%**	**31.50%**
Gas_Peak NPV (mn EUR)	128.67	146.16	173.16
Gas_Peak NPV/MW (mn EUR/MW capacity)	0.43	0.49	0.58
Gas_Peak NPV/ Equity investment	**2.59**	**2.95**	**3.49**
Gas_Peak IRR; CF=0.4	**28.60%**	**31.95%**	**34.60%**

Source: Model calculations

Allocation: Financial versus Policy Effects

The fact that allocation affects the profitability of investments is a trivial insight; the cross-over point, however, from preferring one technology is of policy relevance when trying to design emissions trading schemes to encourage or discourage certain technologies.

This analysis shows coal is put at a relative advantage by generous allocation mechanisms. While the internal rate of return is similar to gas, the investment in coal is more profitable on an NPV/equity metric. This changes in the full auctioning case where the baseload gas is the more profitable investment. The gas peaking case is clearly superior under the assumption that a capacity factor of 0.4 can be attained, but is dominated by coal if a capacity factor below 0.3 is assumed; the sensitivities were shown in the previous chapter. Such analysis exemplifies, how free allocations give a relative advantage to coal and any investor expecting marginal free allocations or facing uncertainty over the frequency of gas dispatch will choose to invest in coal. The allocation effects benefit gas investments only when full auctioning occurs and high capacity factors can be attained. The three scenarios are all presented in the following graph to clarify the impact of the allocation mechanism on the overall profitability of a coal investment. In the most generous case with 14 years of free allocations for new entrants (Scenario 1), the NPV of the coal investment has a mean value of 578 million Euros. The scenario two the mean is shifted to 249.5 million Euros while in the most stringent Scenario 3 the mean NPV is shifted down to 141.8 million Euros.

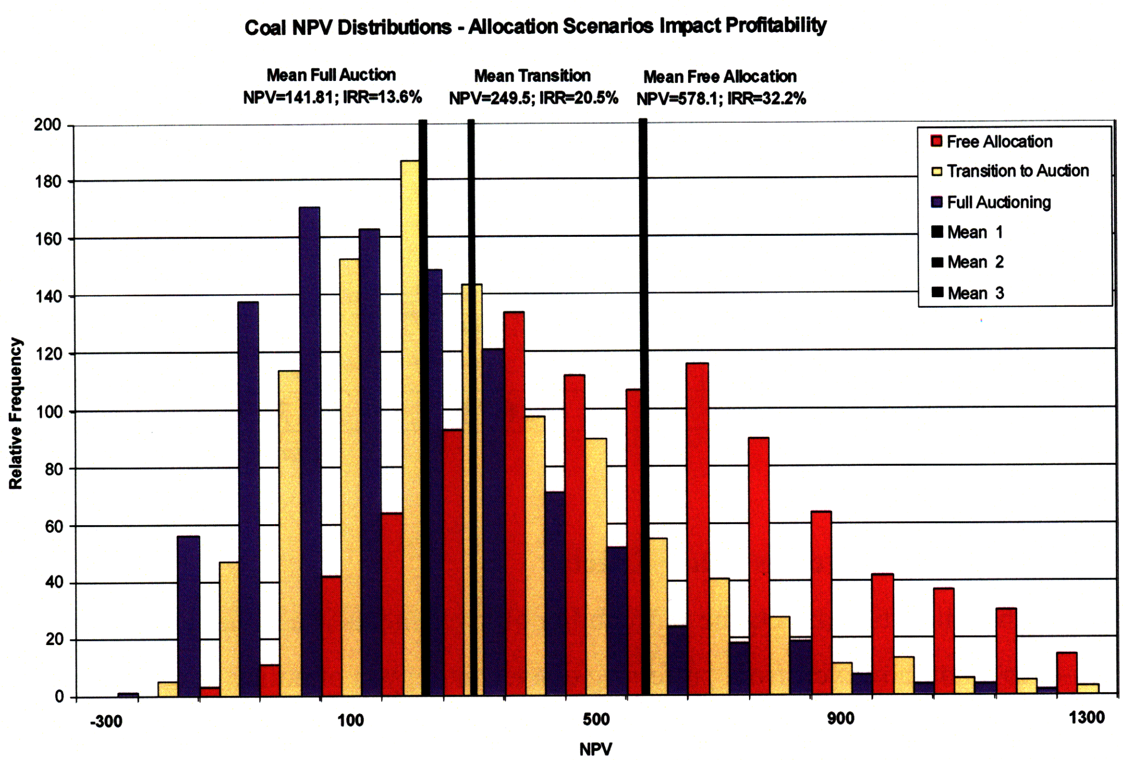


Figure 6.1: Profitability impact of allocation scenarios for coal

Source: Model calculation

Similar mean shifting effects are observed in the case of the gas investment. The most generous allocation would result in a mean NPV of 132.4 million Euros, the second scenario results in a mean NPV of 69.2 million Euros while the most stringent third scenario results in a mean NPV of 39.0 million Euros. Given that gas operated utilities tend to have long-dated gas delivery contracts with non-public pricing clauses, it is very probable that the gas prices assumed here are overstated and that actual returns are much higher.

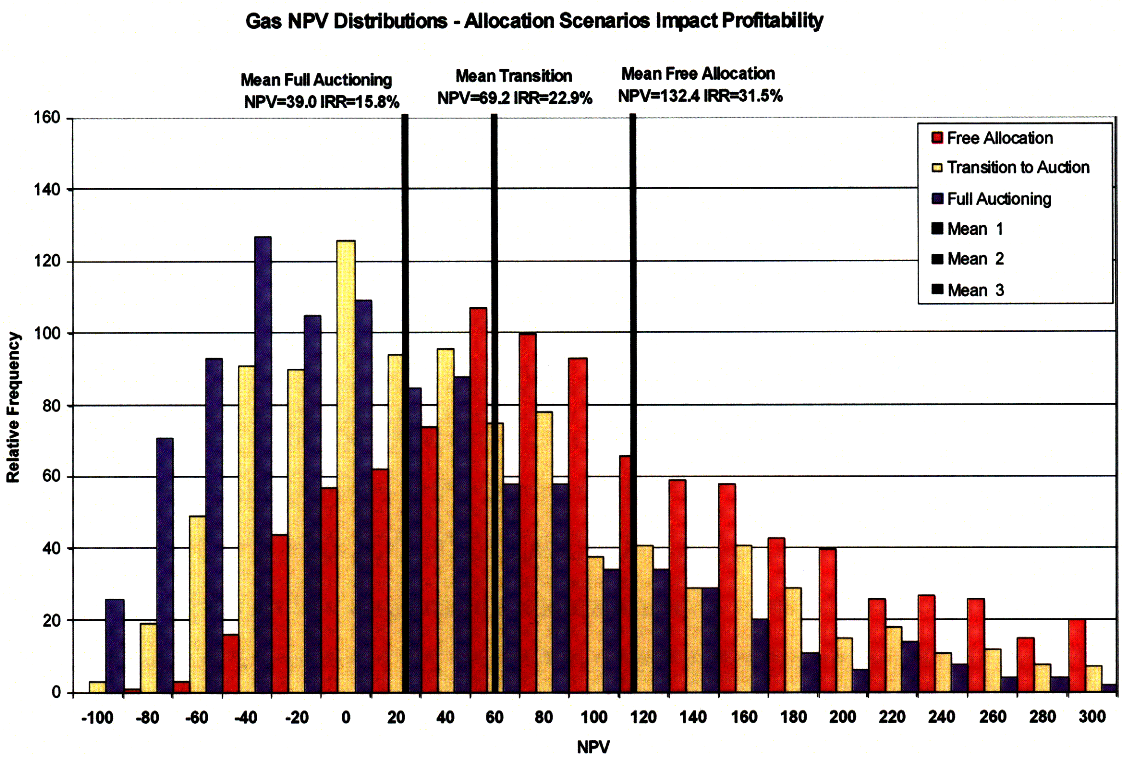


Figure 6.2: Profitability impact of allocation scenarios for gas

Source: Model calculation

The results from this chapter exemplify the large influence that political decisions related to carbon emissions trading have on the power market. Although carbon policy has the most immediate effect, there are, however, other policy areas that also impact the power sector and carbon policy, as will be discussed in the following chapter.

7. Impacts of Related Policy Fields

There are two main related policy areas that impact the power sector, namely the Clean Development Mechanism (CDM) or Joint Implementation (JI) and the Renewable Energy policy. Ironically, both have direct or indirect effects that benefit the long-term outlook for coal investments. The CDM can play an important long-term role in mitigating the necessity for domestic carbon abatement by creating additional, low-cost carbon reductions in the developing world. If a significantly large amount of relatively cheap abatement from CERs/ERUs (carbon credits generated through the CDM and JI respectively) is allowed into the EU-ETS, the effect would be to reduce carbon prices and favor coal investments, all other things being equal. This dynamic merits a closer look at the current pipeline of CDM projects (the JI projects have been relatively small in comparison), as well as an exploration of the CDM as a linking mechanism with other emerging emissions trading systems such as the American Federal emissions trading system, should it be established. The effects of renewable energy policy are discussed, since the abatement has been significant compared with abatement from Phase I fuel switching (as shown in Chapter 2). Furthermore, this analysis will reconcile the top-down and bottom up abatement estimates shown in Chapter 2. The impact of renewables favors coal investments, since the feed-in tariffs for renewables ensures the full dispatch of renewables, displacing higher variable cost gas generation capacity, as will later be shown in this chapter.

7.1. The Role of CDM/JI Credits and Linking Emissions Trading Schemes

Initial observations on the global size of the carbon market and the separate parallel market structures have already been made in Chapter 1 of the thesis. This chapter will discuss the CDM and JI credits that are currently being used for compliance within the EU-ETS as well as national compliance of Annex I nations under the Kyoto Protocol. International negotiations are currently focused on the next round of global climate negotiations to be held in Copenhagen in December of this year. A post-2012 continuation of the Kyoto Protocol moves to the center of international climate negotiations, and the role of the Clean Development Mechanism will play a key role in the outcome of these negotiations. Hence this chapter will discuss the scheme in more detail while providing an outlook to the opportunities and constraints that this market faces from national and regional policy.

The international reductions in carbon emissions that have been negotiated as part of the Kyoto Protocol can either be reached domestically, or they can be purchased using international offsets through the Clean Development Mechanism (CDM) and Joint Implementation (JI). The chief difference between these two schemes rests mainly in the location that these offsets are being generated in. Joint Implementation credits, called Emission Reduction Units (ERU), are generated in emissions abating projects in Annex I countries. To date, this has mainly taken place in former Soviet Union countries, such as Russia and the Ukraine, although first projects have also been developed in Western Europe. The Clean Development Mechanism (CDM) generates Certified Emission Reductions (CER) credits in non-Annex I countries which are essentially developing and emerging markets in South America, Asia, and Africa.

The Conceptual Framework of CDM/JI credits

The conceptual background of a CDM or JI project is outlined in figure 7.1. It assumes that a project in a developing nation with no emissions cap has a certain baseline emissions level. Through implementing a specific technology, greenhouse gas emissions reductions are achieved. Rigorous methodology verification ensures that these emissions reductions are actually "additional", i.e. would not have been attained in a business as usual scenario. The emissions reductions projects are submitted to the UNFCCC Executive Board (EB), which then issues carbon credits upon the verification of the project's credentials. These credits can then be sold to governments to help meet emissions reductions in developed countries, or they can be sold directly to participants of cap-and-trade carbon markets such as the EU-ETS.

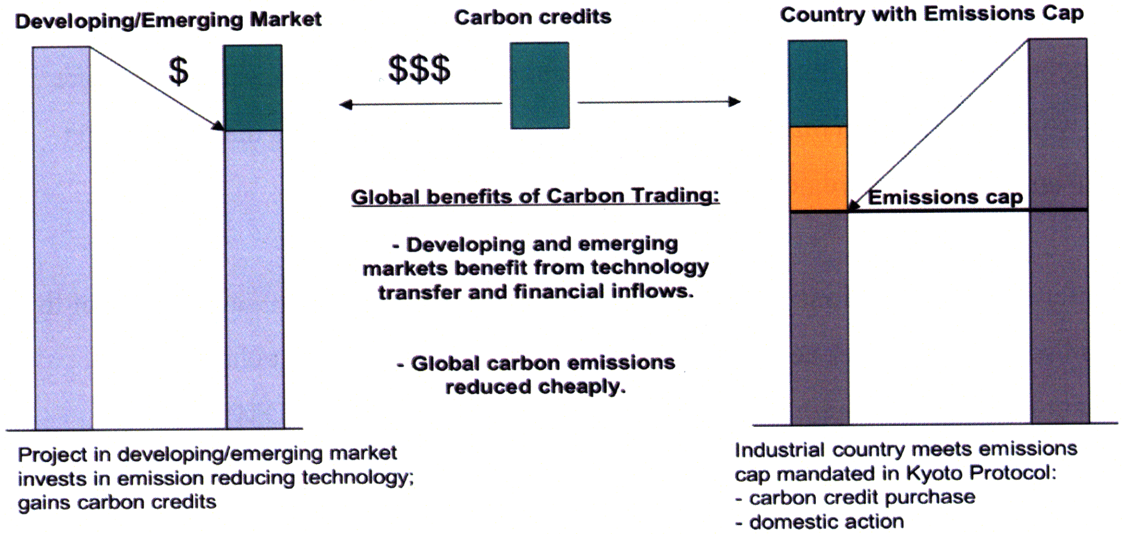


Figure 7.1: Conceptual background of a CDM project

Source: World Bank, 2009

The CDM and JI projects have to undergo significant project documentation and outside verification, before the Executive Board of the UNFCCC reviews the projects on an individual basis. It then decides on whether the projects fulfill all the criteria required to qualify for an emissions offsetting project and hence will be issued carbon credits. Elaborating on the procedural steps required would go beyond the scope of this thesis chapter; however, the main steps are shown in a simplified number of steps that also highlight the different types of risks faced by projects before coming to fruition:

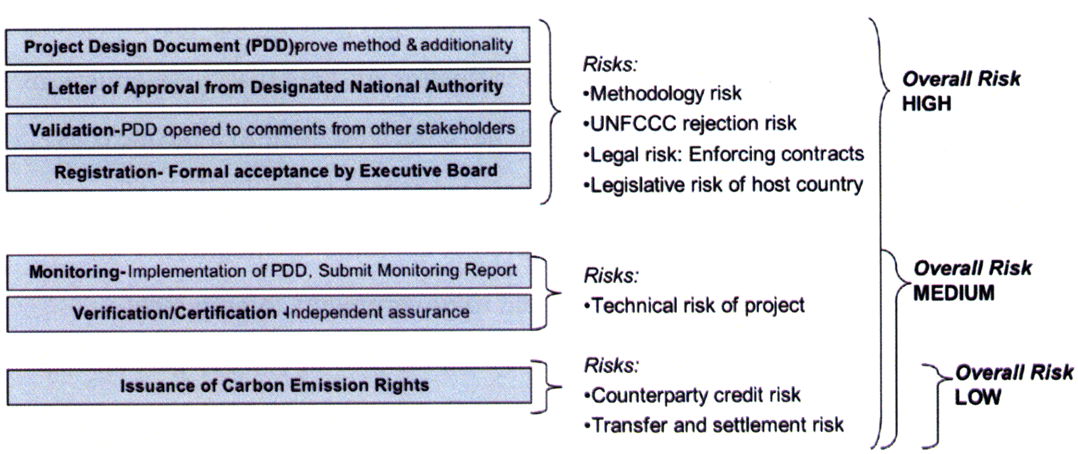


Figure 7.2: Project Risk Matrix

Source: UNFCCC, 2008

Thus, getting a CDM project from the initial project design document (PDD) to the point where the credits are issued by the UNFCC is a long and risky process. The earlier on in the project, the more risk components increase the uncertainty of project delivery. Projects that are not yet formally registered with the Executive Board of the UNFCCC carry very high risks. Projects that passed this stage and are in the monitoring, verification, and certification stages carry medium-sized risks (determined by the operational risk of the project delivering the projected amount of credits). Once credits have been issued to a project, the overall risk is low, since the credit can be readily sold into the secondary market. As a carbon offset project moves along the value chain it requires several technical, financing, and management inputs which all reduce risks and add value. This can be seen in the increasing value of the project as it comes closer to implementation. The pricing of carbon projects is merely indicative and will be negotiated on a project-by-project basis; furthermore, prices are reported based on publications and conversations with market participants in 2008 when overall carbon prices were trading around 20 Euros per ton. Project pricing has contracted as exchange prices have reduced although anecdotal evidence seems to suggest that this applies more to later stage projects that tend to trade in tighter spreads with EUAs; the early projects with high technical risks are, however, priced closer to actual project costs and will thus not be able to sell for lower levels in non-distressed situations.

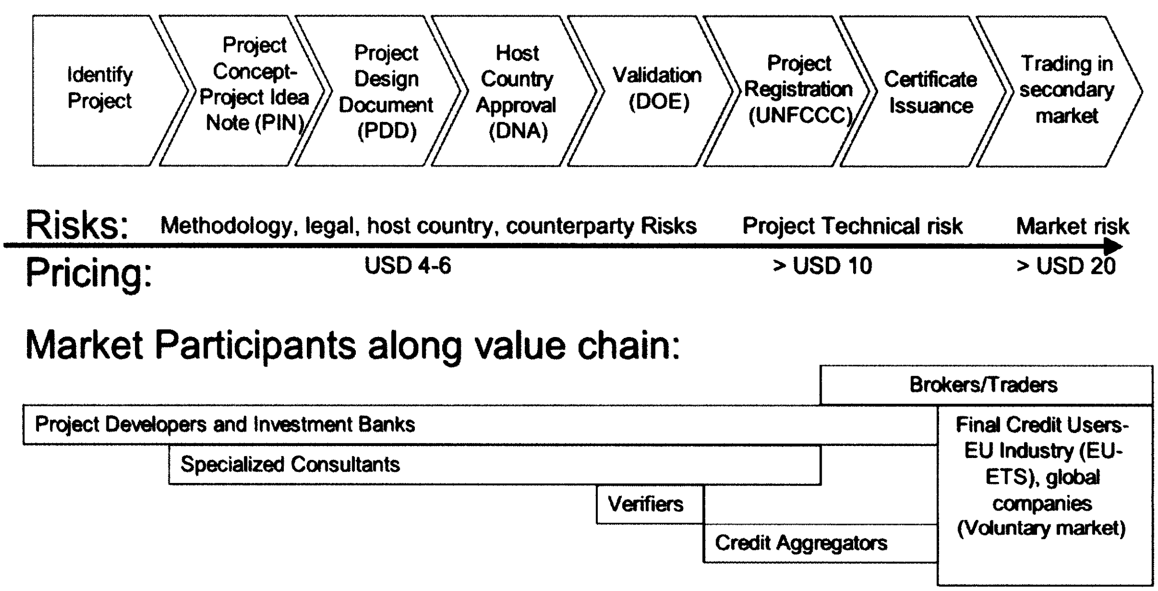


Figure 7.3: Project Value Chain, Market Participants and Pricing

Source: UNFCCC, World Bank 2009

Sizing the Carbon Project Market:

The global carbon project market has grown significantly since the first projects started to be developed, following the negotiation of the Kyoto Protocol. Given that the JI market is only beginning to deliver carbon credits and the CDM market is orders of magnitude larger, the analysis of the market will focus on the latter. As of February 2009, the publicly available pipeline of the global CDM projects has reached almost 4500 sites globally that are expected to deliver almost 3 billion credits by 2012. Most market analysts apply a significant discount to account for the risks associated with the projects; however, if just half of the proposed projects get delivered the volume will still be significant.

Projects by Technology

One of the key objectives of the CDM is to promote technology exchange. Every new method of generating carbon credits needs to be approved by the UNFCCC before it can be used to generate credits.

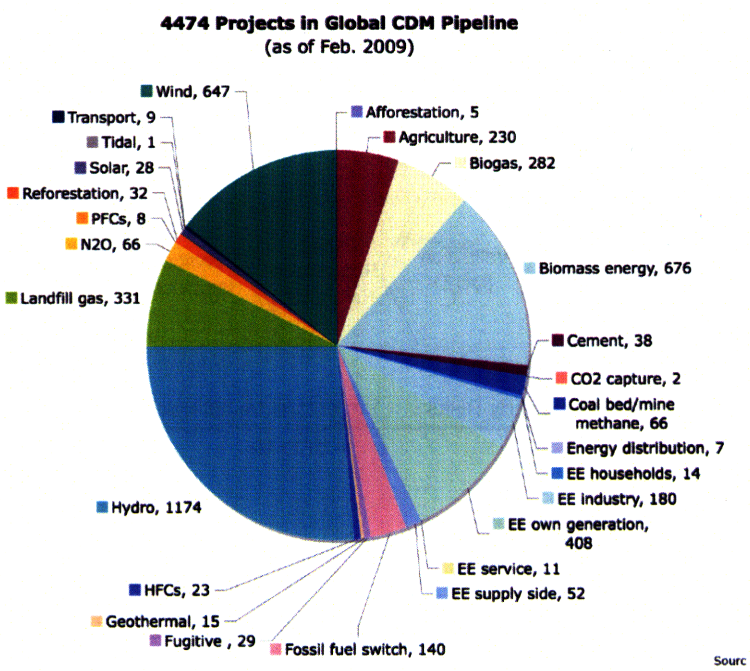


Figure 7.4: Global CDM Pipeline by Technology (as of February 2009).

Source: UN Riso

Already approved methods can be classified into broader technology types. Most projects use hydro technologies (1174), biomass energy (676), wind (647), energy efficiency based on own generation (408) and landfill gas (331). By far the largest projects are those intended to reduce the most toxic gases. The sulfur hexafluoride projects, HFC and industrially-sized N2O projects account for 26 percent of the 2.9 bn tons of 'avoided' carbon even though they only account for 2 percent of the total projects in the pipeline.

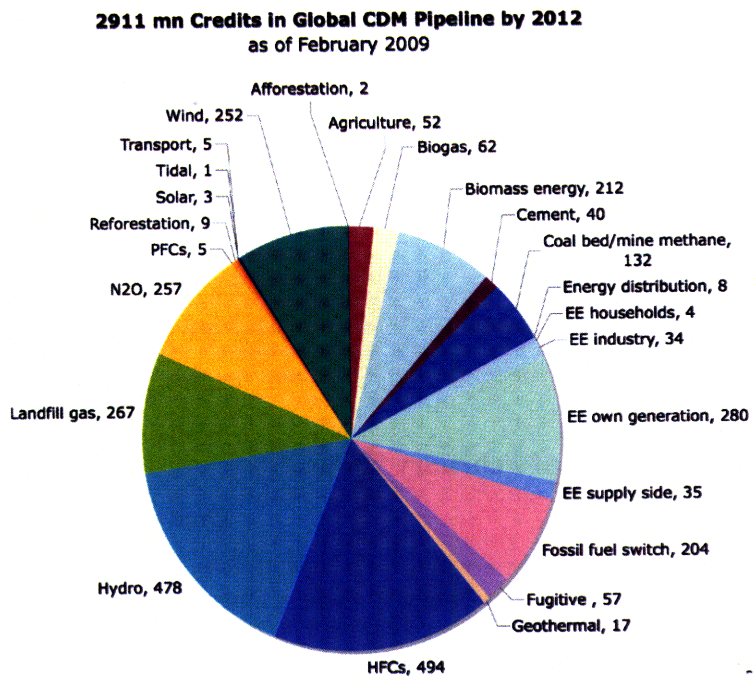


Figure 7.5: Global CDM Pipeline by Volume (as of February 09)

Source: UN Risoe

India, China, South Korea and Brazil are the countries where most carbon credits have been issued thus far, with these four players accounting for almost 90% of the market as is shown in the figure on the next page:

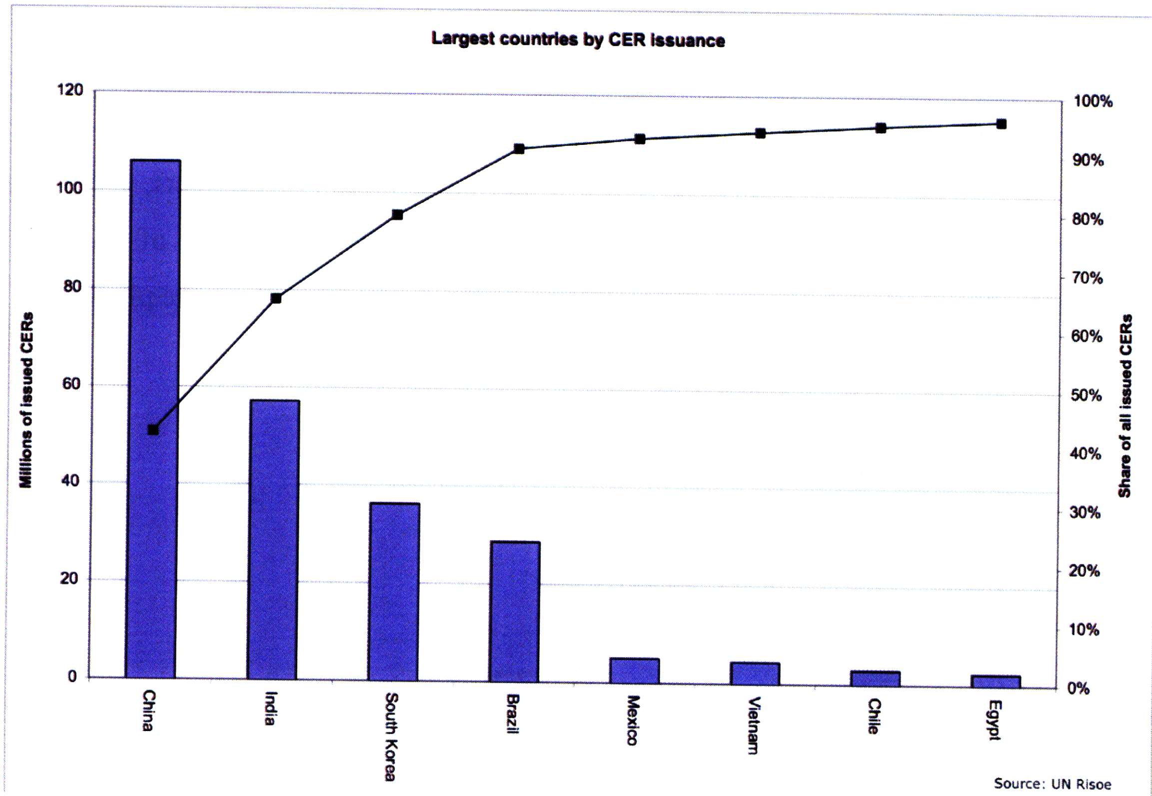


Figure 7.6: Largest CER issuers to date (as of February 2009)

Source: UN Risoe

Key Policy Uncertainties relating to the CDM/JI

The European Commission does not tire of reaffirming its support for emissions trading beyond 2012, regardless of whether or not there will emerge a global consensus for the continuation of any carbon reduction goals beyond the Kyoto Protocol. However, significant policy uncertainties for the use of CDM/JI credits within an emissions trading scheme do exist. For instance, the allowance of CDM/JI projects for compliance within the EU-ETS has been decreasing from phase to phase. In Phase I, there had been no limit[5], but in Phase II member states allowed differing amounts of CDM/JI to be used for compliance, and this allowance can be banked into the third phase (Germany allowed 12% of total allocation to be used). Post-2012 will allow using CDM credits amounting up to 3% of a country's non-ETS emissions, and any unused "capacity" can be traded between EU-ETS participants. In addition to this, the EU Commission will continue to

[5] Even though there had been no cap on the use of CDM/JI credits in Phase I, the slow registration of credits at the UNFCCC Executive Board and the lack of a common IT platform integration hindered any significant amount of CDM credits to be surrendered under Phase I.

allow all CDM credits from projects in Least Developing Countries that were registered between 2008 and 2012. Given protectionist tendencies and fears of carbon leakage through non-additional projects in developing countries, the total amount of CDM credits finally allowed during Phase III could even be below this number, greatly reducing the demand in the global market.

Linking of Schemes and Arbitrage

One often discussed topic is the linking of different emissions trading markets, and the obvious candidates for linking would be the EU-ETS and the Federal American carbon trading scheme if it comes into being. Using the same "carbon currency" or accepting the emissions allowances from other linked-up schemes can directly link different markets. While it is very difficult to predict the exact form of the US scheme, given the myriad of proposals currently being debated in the House of Representatives and the US Senate, it is very possible that an American scheme will not be directly fungible with the EU-ETS, although both schemes might accept the CDM. In such a case the CDM would flow to the higher price scheme, leading towards a convergence of prices. A non-compliance buyer could, for example, arbitrage the spread between the two schemes and "exchange" the carbon credits using the CER as an intermediary currency in two steps:

1. An EU-ETS market participant sells an EUA and purchases a CER
2. The CER is bought by an American buyer who then sells the CER and purchases an American emissions allowance

In this way, a European credit has been, in effect, sold to an American compliance buyer and would be a way to arbitrage prices and to force at least partial convergence of prices. In an efficient market with zero transaction costs and no cap on the amount of CER credits allowed into the market, the two emissions trading regimes would thus be linked and prices would be equal. Given that the market is likely to be shielded from both sides, most notably through price floors and ceilings, the actual integration of the markets will likely be limited.

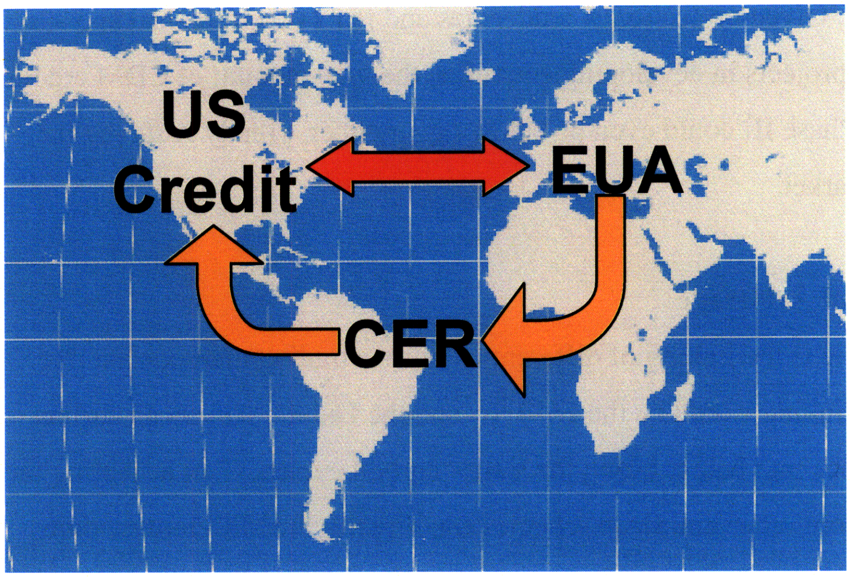


Figure 7.7: Linking of Schemes via the CDM

Source: World map image taken from http://www.webresourcesdepot.com/wp-content/uploads/image/free-vector-world-map.gif

7.2 Impact of Renewable Energy Policy on Carbon Abatement

In addition to CDM and JI, emissions trading is also affected by Renewable Energy policy which, perhaps unexpectedly, can favor marginal investments in coal over gas. The growth of Renewable energy has been stunning, aided by aggressive government targets in many legislations as a means to diversify energy generation portfolios and reduce overall carbon emissions. The European Union, home of some of the most generous feed-in tariffs, has set itself ambitious goals, namely to derive 20% of the energy mix from Renewable energy by 2020, compared to 8.5% today, with intermediate targets being set in two year intervals to ensure that countries deliver their mandates. These targets are specified on a member-state level, with all countries having to increase the use of renewables by 5.5% with the remaining increases being mandated to the strongest economies as measured by GDP. These targets are outlined in the figure below:

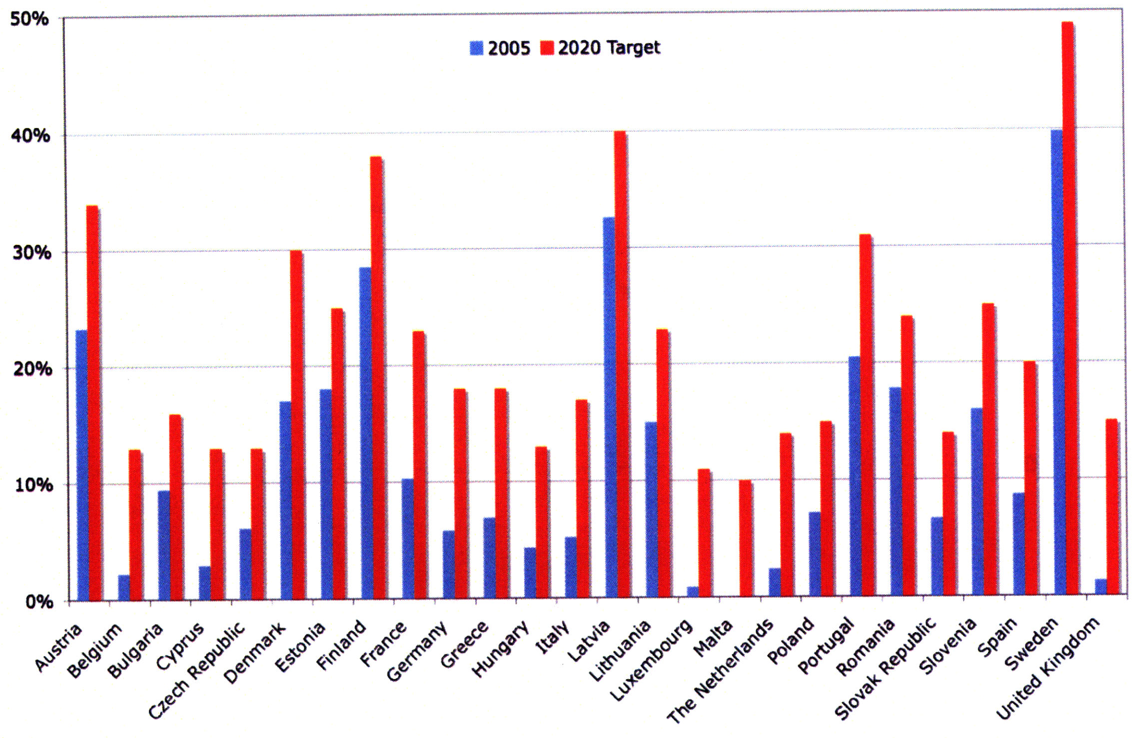


Figure 7.8: Renewables portion of total energy in 2005 and 2020 Goal

Source: Euractiv, 2009

The large contribution of renewables to Germany's total energy has already been discussed in Chapter 2. As of 2009, the government feed-in tariffs have been further adapted to encourage the development of offshore wind and the repowering of existing renewable energy assets. The German Federal Ministry of the Environment (Bundesumweltministerium) estimates that in 2007 alone, Renewable Energies resulted in 78.9 million tons of carbon abatement. However, the top-down estimates are based on 2000-2004 trends, so one can only count the marginal abatement since the trend years, otherwise double counting the abatement from renewables that had already occurred by the base year of the trend. Since the carbon abatement from renewables, such as hydro, is relatively steady, the real impact on emissions is gained from the advances in wind and solar. The data takes 2002 as the base year and hence finds marginal abatement from renewables as 10.6, 13.1 and 22.6 million tons for 2005, 2006 and 2007 respectively.

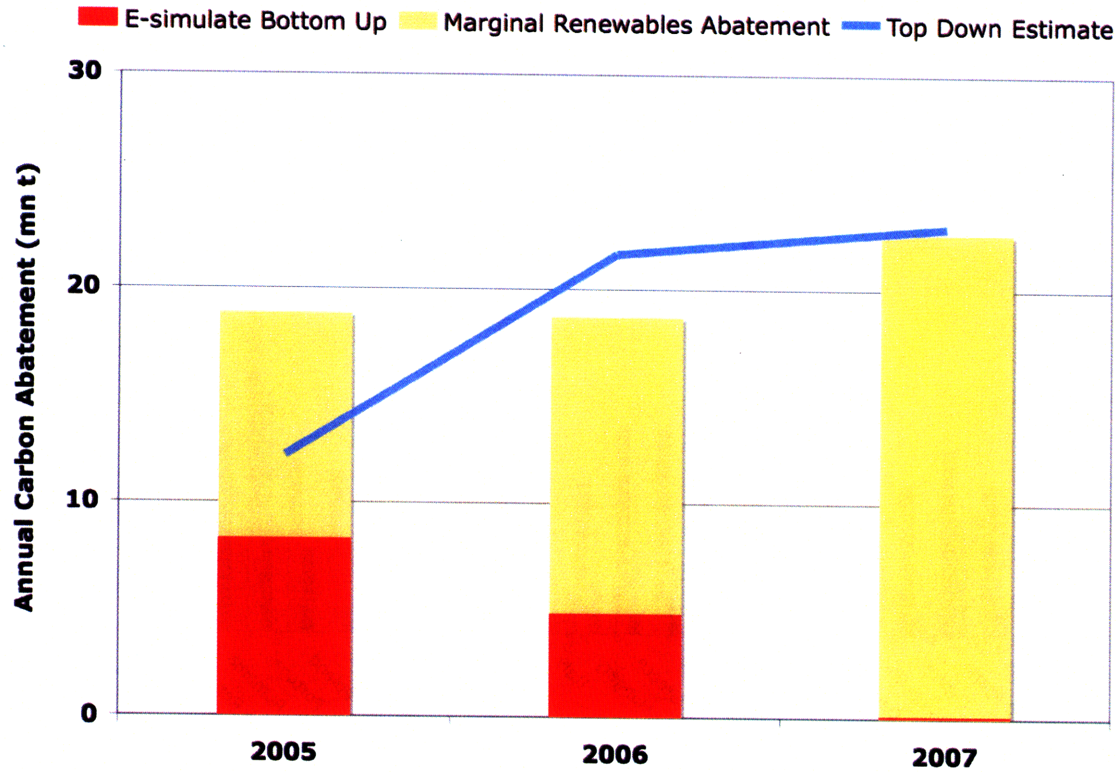


Figure 7.9: Abatement Estimates and Reported renewables Abatement

Source: Authors' calculations and BMU 2008, 2007, 2006

The top-down estimate that is compared to this bottom-up data is based on the carbon intensity trends using power sector data. The top-down and bottom-up data coincide relatively well; this shows that marginal abatement from the renewables sector is most likely the other source of carbon abatement, next to abatement from fuel switching that was calculated in Chapter 2 using the E-simulate model.

The data shows that during times of high carbon prices, the marginal abatement from carbon trading is comparable to the marginal abatement from wind and solar power, and the data from 2008 onwards which showed relatively high carbon prices will show more significant abatement.

Interaction of the Renewable Energy on the Merit Order

One of the key interactions of Renewable Energy is that it displaces high cost capacity from the total power generation mix. Since Renewable Energy in Germany benefits from very generous feed-in tariffs they are always effectively dispatched. Reinaud (2003) discusses how a higher use of renewable energy production results in lower thermal production and hence leads to a reduction of total emissions.

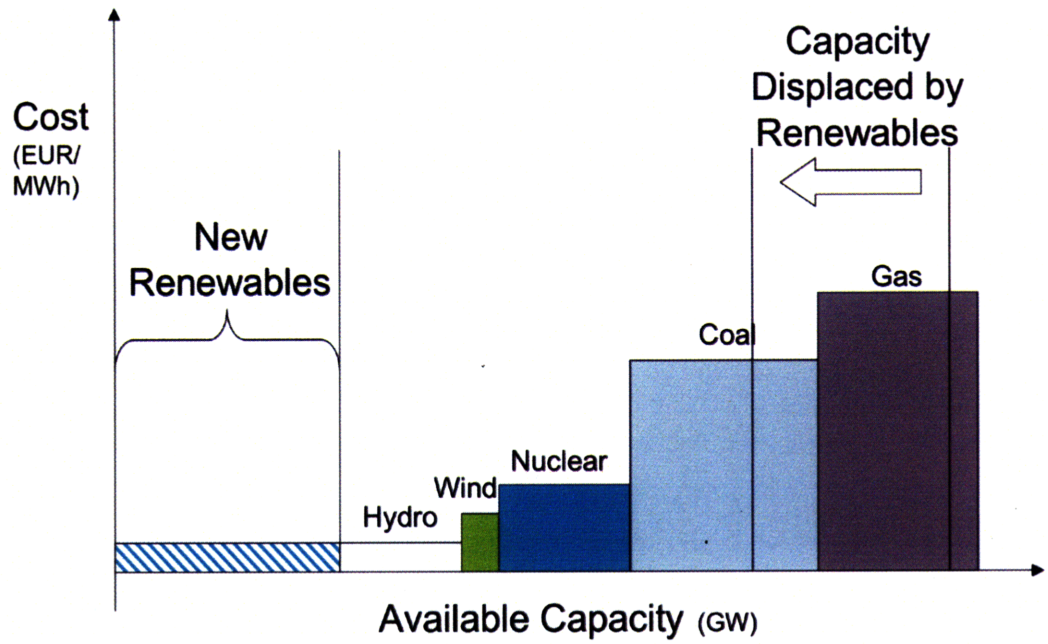


Figure 7.10: Renewable Energy mandates displacing fossil capacity

Source: Renaud 2003.

The impact this has on the relative use of gas and coal power assets depends on the level of the carbon price and marginal fuel during the point of renewables dispatch. Thus renewables will displace fossil fuel capacity and, depending on the merit order, this will either be coal or gas, leading to a reduction in a capacity factor. In a low carbon price scenario this would almost certainly displace gas capacity, as shown in a schematic manner in the graph above. It will also definitely displace the low efficiency gas plants that are among the last to be dispatched, unless carbon prices rise very high and thus increase the number of hours in which coal is the marginal fuel. While the overall effect is a reduction in carbon emissions, the overall long-term impact is to reduce the absolute capacity of fossil fuel dispatch. From the sensitivity analysis shown in Chapter 5, a slight reduction in the capacity factor for coal plants has a smaller impact on profitability than a reduction of the capacity factor in gas plants. This in turn, reduces the long-term profitability of gas investments and helps to explain, why marginal power investments in

Germany have been mostly in Renewable Energy, such as wind and – in fossil power – could be seen to favor coal over gas.

8. Discussion and Conclusions: Assessing the Outcomes

This chapter seeks to summarize the economic and environmental policy effects of carbon trading; it also seeks to summarize the evidence presented in this thesis for the preference of coal over gas investments in Germany.

8.1. Conclusions on Economic Implications of Carbon Trading

The persistence of coal in the German power sector comes down to the fact that coal has been the more profitable fuel in Germany and continues to be so. Three different analysis metrics and methods have been applied in this thesis: Return analysis, marginal fuel analysis from the bottom-up model, and spread analysis from commodity prices. The application of these methods has found a preference for coal; unless the fundamental commodity prices or power generation technologies significantly reduce the costs of gas-fired generation, the trend for coal investments in the fossil fuel space are unlikely to change.

As shown in details in Chapter 5 of the thesis, the return on equity investments and net present value of a gas plant investment is slightly higher than that of coal in the base case scenario. Yet, after adjusting the base case to lower capacity factors closer to what has been observed in the market, coal is more profitable. Both factors became evident in the analysis of sensitivities assuming the base case of technologies available, fuel prices, and carbon prices. The net present value assumes the allocation mechanisms as decided by the European Parliament in December 2008. The net present value of the coal plant investment is 141.8 mn Euros with an internal rate of return of the project cash flows of 13.6% while the gas plant dispatched as baseload has a mean NPV of 39.0 mn Euros and an IRR of 15.8%; a peaking plant results in an NPV of 128.7 mn Euros and an IRR of 28.6%. These figures represent the mean of the investments, generated using 10,000 Monte-Carlo draws based on the price distributions of the relevant fuel and carbon price distributions. Both investment options have a possibility of generating negative returns. It is important to note that all the assumptions for the discounted cash flow model are very conservative, and sensitivity analysis shows that coal investments could be more profitable when looking at the fuel spreads seen on the power markets over Phase I. Power prices have increased significantly since the introduction of carbon trading to reflect, among other things, the opportunity and real costs of carbon. Hence, the lower part of the distributions represents power price levels that are unlikely to be seen in the market unless fuel prices decrease significantly.

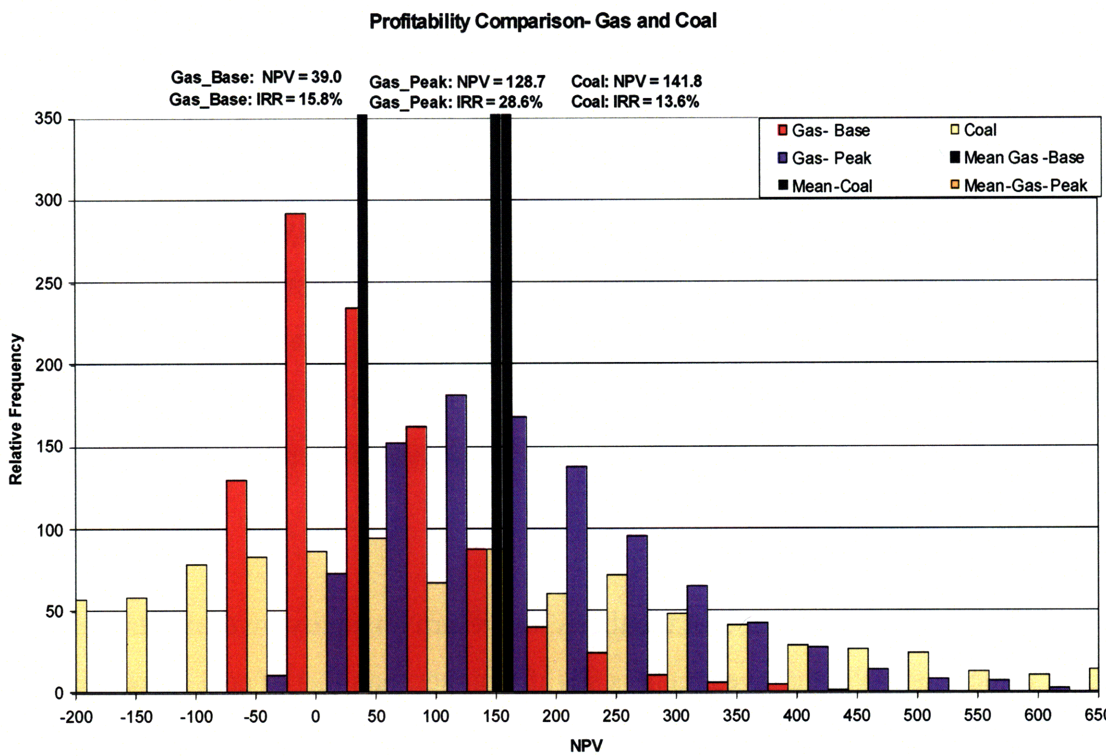


Figure 8.1: Net Present Value Distribution and Mean Returns

Source: Model calculations

8.1.2. Marginal Fuel analysis translates into low capacity factors for gas

Chapter 2 has discussed the use of the bottom-up power sector model, "E-simulate", which was used to estimate carbon abatement from short-term fuel switching. This least cost linear optimization model calculates optimal dispatch of the available generation fleet in hourly intervals. One of the outputs that this model generates is the marginal fuel of the power system every hour. When the ramping constraints associated with the various generation technologies are applied and the daily carbon prices are accounted for, the model provides the marginal fuel, which makes evident how many hours of the year coal or gas plants can be operated profitably. In reality, utility companies are unlikely to change the dispatch of large amounts of capacity based on these movements, yet if one assumes that the power plant investment meets only marginal demand, one can use the marginal fuel as an indicator for the likely capacity factor to be expected for gas. In both power investment models, the capacity factor is the second most sensitive input variable after the full load efficiency that is determined chiefly by the technical attributes of the power plants. What becomes apparent from this type of analysis is that capacity factors for gas plants could potentially be much lower than the 80-85% assumed in the investment model, as gas plants are only running at peak times. This deteriorates the economics of gas plants and increases the relative attractiveness of coal investments.

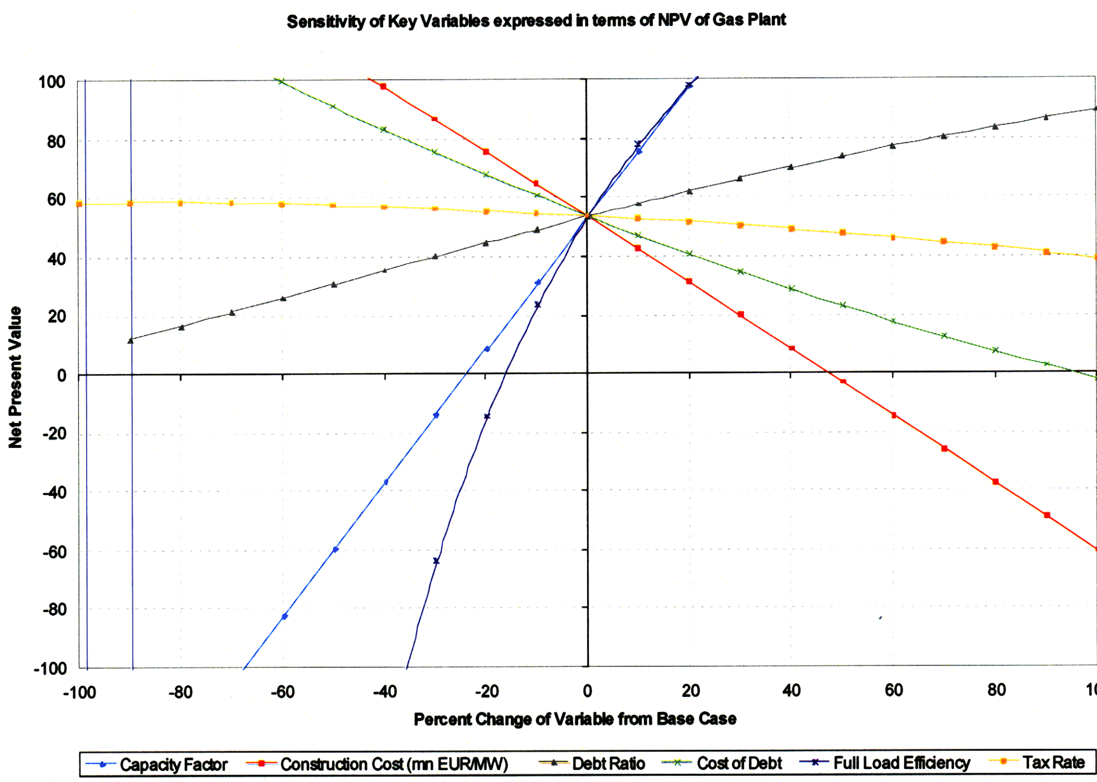


Figure 8.2: Sensitivity of Key Variables of a Gas Investment

Source: Model calculations

A more in-depth model would add the marginal investment plant to the bottom-up model and iteratively run the bottom-up model year by year. This would require significant assumptions on forward-looking hourly power demand, the annual changes in all segments of the power generation portfolio, as well as price forecasts over the entire plant life. Long term, large-scale analysis methods become sensitive to the economic feedback effects, which would require different types of models. MARKAL models, for example, iteratively solve engineering cost models that are linked with a partial or general equilibrium models to simulate economic feedbacks. This type of analysis, however, is beyond the scope of this thesis, but would be an obvious choice for extending this research.

Larger spreads strengthen coal and fuel prices dominate carbon effects

One of the key analysis metrics used in the power industry are the spreads that a company is earning for generating power. These spreads make several simplifying assumptions on the production efficiencies of the power producing assets and take the heat rates of the respective fuels into consideration. The simple spreads only account for marginal costs and do not include the need to recoup capital costs for the investments. Positive spreads indicate that it is more profitable to generate power than to purchase the electricity from the market. These spreads are quoted on Bloomberg; there is, however, only very limited historic data available for these spreads. Hence, the spreads were recreated from first principles using long-dated price series. While the absolute value of the spreads is interesting, the real question for making a relative investment decision between coal and gas is the movement of the difference of the dark and spark spreads.

The figure below gives a long-time series of these spreads from the end of 2000 until February 2009. The figure shows the difference of the clean spreads, i.e. those spreads that already account for the carbon price.

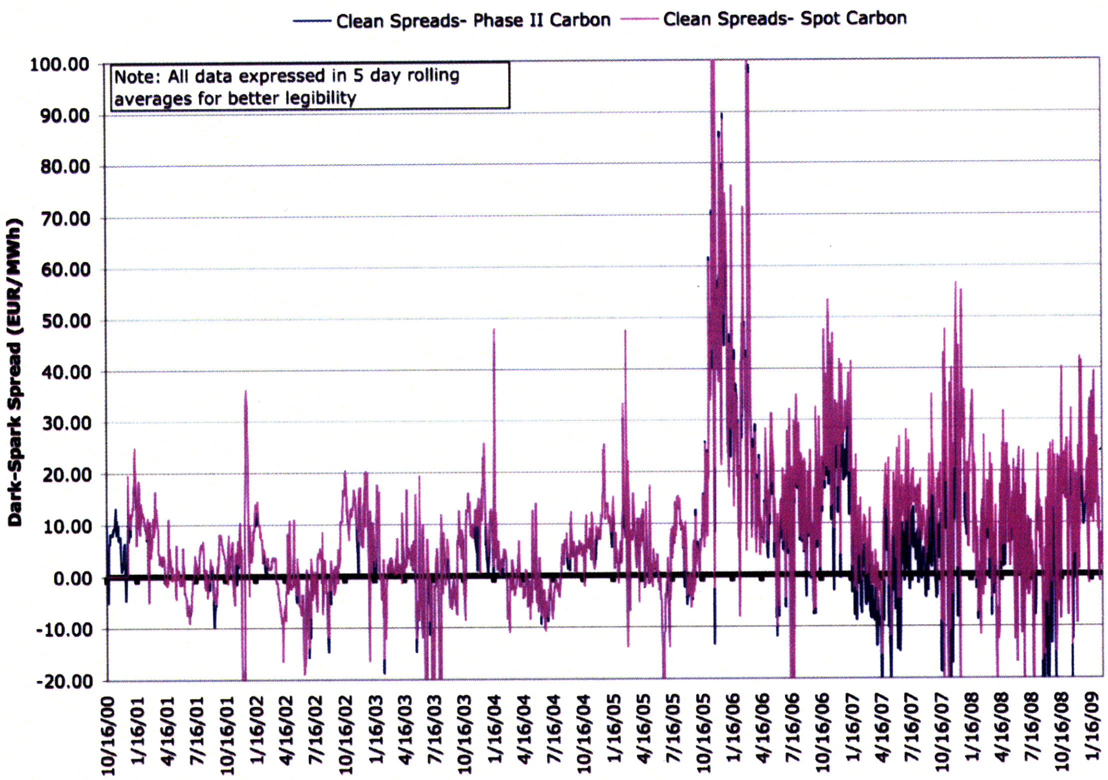


Figure 8.3: Clean Spreads for Coal and Gas from 2000-2009

Source: Bloomberg, ECX, model calculations

The outcome is striking. The large majority of days show a higher profitability of coal plants versus gas plants. There are clearly seasonal effects of commodity prices that can be seen in the data; over the summer month, when gas prices tend to be lower than in the winter months, the dark-spark spread briefly turns negative, indicating that it is more profitable to operate a gas plant. Moreover, the absolute value of the spread difference indicates that coal plant investments have actually become *more* profitable versus gas since the introduction of carbon emissions trading. This is a slightly counter-intuitive result, but with great explanatory power for the recent announcements of new coal builds as outlined in Chapters 3 of the thesis. While in the time before carbon emissions trading, it was more profitable on 65.7% of trading days to operate coal power plants versus gas plants. During the emissions trading scheme this increased to 81.5% of trading days, showing a clear preference for coal over gas. Even if one uses Phase II carbon prices, coal still prevails in 73% of the days.

Table 8.1: Clean Spreads using spot prices for carbon

	Clean Spreads using Phase II Carbon	Clean Spreads and Spot Carbon		2000-2004 with Hypothetical Carbon Prices	
	2005-2008	2005-2008	2000-2004	8 EUR	15 EUR
Days with Positive Spread	707	745	617	406	260
Total Days with Data	969	914	939	939	939
Fraction Coal Dominance	**72.96%**	**81.51%**	**65.71%**	**43.24%**	**27.69%**
Fraction Coal Dominance-Capital Cost Adjusted	**69.45%**	**78.34%**	**58.25%**	**36.53%**	**24.07%**

Source: Bloomberg, model calculations

8.2. Environmental Goals and Environmental Policy Issues

Having ascertained the clear economic argument for why coal is preferable in comparison with gas in Germany, there are the remaining issues of the environmental goals and the interactions of carbon trading policy with other environmental policies, as already discussed in Chapter 6.

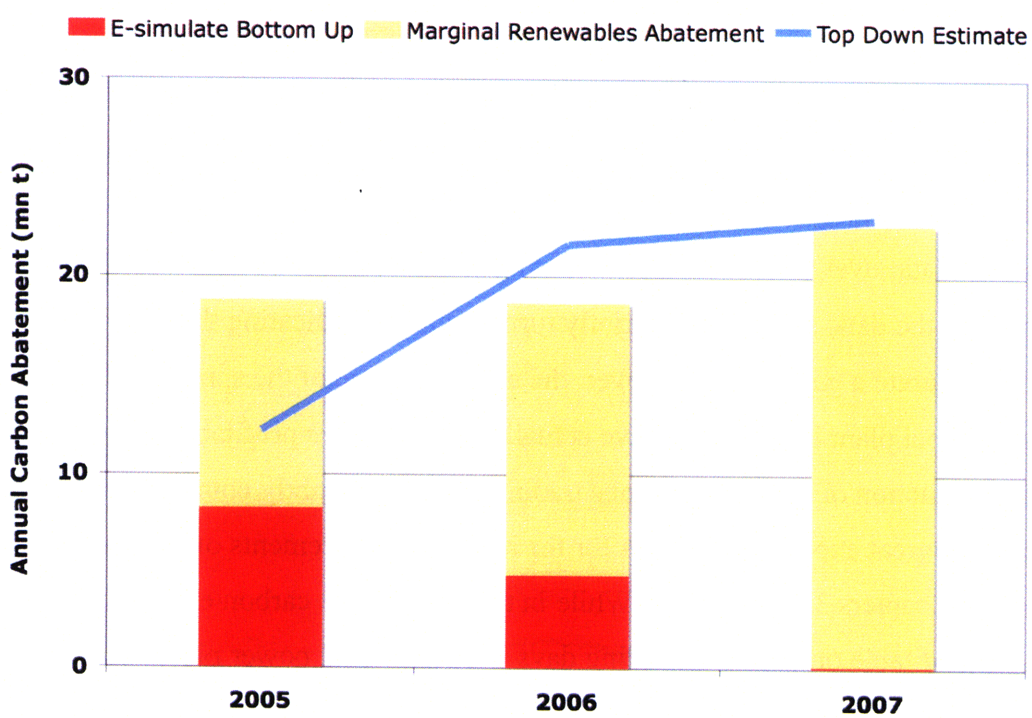


Figure 8.4: Top down and bottom up estimates of abatement in the power sector

Source: BMU and model calculations

Carbon emissions trading is only one mechanism to reduce the carbon intensity of the economy and the power sector more specifically. Chapter 2 discusses the mechanisms of fuel switching and calculates bottom-up values of the carbon abatement due to utilities dispatching gas rather than coal. Top-down approaches look at the carbon intensity of the economy or parts of the economy and use these trends to establish an emissions counterfactual against which abatement can be measured. Chapter 7 discusses the mechanism of how marginal abatement from renewables and fuel switching correlate closely with the top down abatement estimate of the power sector.

Outlook to Future Work

The work applies several top-down and bottom-up modeling techniques for assessing the impact of a carbon price on the power sector. The thesis has quantified the short-term carbon abatement potential from fuel switching as well as presented long-term effects of the carbon price on investment behavior. The various model outcomes are compared and reconciled with first empirical data that has become available since the inception of the European emissions trading scheme in 2005. While the discussion of the results has focused on the key assumptions and outcomes, the results presented in this thesis could be used as a foundation for future research. For example, the wider implications of a carbon price on investment effects could be modeled such as more granular technology options in coal and gas plants, or utility-scale Renewable energy options such as a wind or technologies such as CCS to continue the work of this thesis in understanding the in-depth effects of the carbon price.

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Annex I:

Mean Values and Distribution Types of All Data Series used:

Data Series:	Units	Mean	Distribution Type
Gas-2000-2008	EUR/TJ	4244.59	Log-normal
Gas-2005-2008	EUR/TJ	5860.60	Normal
Coal-2000-2008	EUR/t	57.56	Log-normal
Coal-2005-2008	EUR/t	74.38	Log-normal
Carbon: 2005-2008- Dec 09 contract	EUR/t	20.40	Normal
Power-Base: 2000-2008	EUR/MWh	36.64	Beta
Power-Base: 2005-2008	EUR/MWh	51.51	Log-normal
Power-Peak: 2000-2008	EUR/MWh	70.97	Log-normal
Power-Peak: 2005-2008	EUR/MWh	71.76	Beta
Power-Base: 2005-2008- Zero Pass	EUR/MWh	32.09	Beta
Power-Base: 2005-2008- 0.25 Pass	EUR/MWh	37.05	Beta
Power-Base: 2005-2008- 0.5 Pass	EUR/MWh	42.01	Beta
Power-Base: 2005-2008- 0.75 Pass	EUR/MWh	46.96	Beta
Power-Base: 2005-2008- Full Pass	EUR/MWh	51.92	Beta
Power-Base: 2005-2008- 1.25 Pass	EUR/MWh	56.88	Beta
Power-Peak: 2005-2008- Zero Pass	EUR/MWh	64.15	Beta
Power-Peak: 2005-2008- 0.25 Pass	EUR/MWh	66.04	Beta
Power-Peak: 2005-2008- 0.5 Pass	EUR/MWh	67.93	Beta
Power-Peak: 2005-2008- 0.75 Pass	EUR/MWh	69.82	Beta
Power-Peak: 2005-2008- Full Pass	EUR/MWh	71.72	Beta
Power-Base: 2005-2008- 1.25 Pass	EUR/MWh	73.61	Beta

Annex II:

The investment model is difficult to represent in paper form and screen shots did not print in a sufficiently legible quality.
For a copy of the excel and MATLAB files please email the author at stephan_marvin@yahoo.com