Investments in Liberalized Electricity Markets and the Low-Carbon Energy Transition: A Mixed-method Analysis of the German Case

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Summary

Because of the high number of low-cost mitigation options the power sector will play an important role in combating global climate change. Given the current worldwide trend of liberalization, the main challenge is to incentivize investments in low-carbon technologies under market rules. This thesis investigates the combined questions of how investments are made in liberalized electricity markets, and to which extent climate policy instruments are effective in inducing cleaner technology choice. It uses Germany as a case study, where during the last years a considerable number of new coal power plants have been brought on the way. This "dash for coal", apparently contradicting political efforts to transform the energy system, serves as the guiding issue around which several aspects of the aforementioned questions are investigated.

The first analysis explores the drivers and decision factors that likely triggered the "dash for coal". Because no integrated theory of investments in liberalized electricity markets yet exists, it compiles a list of potentially influential economic, technological and socio-political factors in a first step. Examining these factors in more detail in a second step, it turns out that the extensive coal investments can be attributed to six main reasons. They are: (1) replacement requirements due to the nuclear phase out, (2) the onset of a new investment cycle in the power market, (3) favourable economic and technological prospects for coal compared to natural gas in the long run, (4) a status-quo bias of investors in regard to future renewable deployment, (5) explicit political support for coal, and (6) the ineffectiveness of public protest in hampering new projects. Two of these are looked at in more detail in the succeeding parts of this thesis.

The second analysis deals with how emission certificate allocations had distorted fossil investments in favour of coal technologies. The EU Emission Trading Scheme (EU ETS), implemented in 2005, was set up to incentivize cleaner investments by putting a price on CO_2 emissions through tradable certificates. However, in its first phase initial certificate allocations for new plants in Germany were technology specific, leading to a considerably higher number of total certificates for coal compared to natural gas. Because suppliers incurred windfall profits by passing-through the opportunity costs of these certificates, coal plants were expected to receive higher additional cash flows than natural gas plants, which effectively subsidized coal. In fact, results suggest that disproportionate windfall profits compensate more than half the total capital costs of a hard coal plant. Only auctioning of certificates or a single best available technology benchmark would have made natural gas the predominant technology of choice. This underlines that implementation details had a great impact on investment incentives, unintentionally increasing the edge of coal over natural gas rather than decreasing it.

The third analysis leaves the level of the single investor and looks at how the market as a whole responds to a price on CO_2 under the situation of a nuclear phase out that induces consideral replacement investments. More specifically, it investigates technology choice and the optimal CO_2 price level from a welfare perspective. Motivated by the structure of the German market where four big suppliers own the major share of capacities, imperfect competition with strategic behaviours by these suppliers is assumed. Moreover, based on the finding of the first analysis, investments in coal plants are limited to the strategic suppliers, which adds a so called technological market power. Model results indicate that in such a setting investments in natural gas occur at lower CO_2 price levels and more gradually than in a perfect competitive market. This happens due to the strategic reduction of output that increases electricity prices, which in turn makes natural gas profitable even when the comparative advantage in emission costs is still low. In a perfect competitive market though, investments switch from exclusively coal to exclusively natural gas when the CO_2 price is 37 EUR/t or higher. Furthermore, the impact of market power on overall welfare is relatively moderate and losses never exceed 1% if the price of CO_2 is set at the optimal level. This shows that a price on CO_2 can indeed be a suited instrument to induce investments into cleaner technologies, especially natural gas. Nevertheless, relatively high prices are needed for a fundamental transition, and it remains to be seen if this will become reality in the future.

Zusammenfassung

Aufgrund der großen Zahl günstiger Vermeidungsoptionen spielt der Stromsektor im Kampf gegen den globalen Klimawandel eine wichtige Rolle. In Anbetracht der weltweit stattfindenden Liberalisierungen besteht die Hauptaufgabe darin, Anreize für Investitionen in kohlenstoffarme Technologien im Umfeld der Märkte zu schaffen. Diese Arbeit untersucht die miteinander verbundenen Fragen, wie Investitionen in liberalisierten Strommärkten getätigt werden, und in welchem Umfang klimapolitische Instrumente eine "saubere" Technologiewahl induzieren können. Als Fallbeispiel dient Deutschland, wo innerhalb der letzten Jahre eine größere Zahl neuer Kohlekraftwerke in Bau gegangen sind. Dieser *Dash for Coal*, der offensichtlich im Widerspruch zu aktuellen politischen Bemühungen hinsichtlich des Umbaus des Energiesystems steht, wird als Ausgangspunkt genommen, um verschiedene Aspekte der erwähnten Fragen genauer zu untersuchen.

Die erste Untersuchung erkundet die Treiber und Entscheidungsfaktoren, die vermutlich zum *Dash for Coal* geführt haben. Weil eine umfassende Theorie von Investitionen in liberalisierten Strommärkten noch nicht zur Verfügung steht, wird in einem ersten Schritt eine Liste möglicher ökonomischer, technologischer und soziopolitischer Einflussfaktoren zusammen gestellt. In einem zweiten Schritt werden diese Faktoren genauer betrachtet, und es zeigt sich, dass es aus insgesamt sechs Gründen zu den umfangreichen Neubauten gekommen sein könnte. Diese sind: (1) Der Ersatzbedarf an Kapazitäten aufgrund des Kernenergieausstiegs. (2) Der Beginn eines neuen Investitionszyklus im Strommarkt. (3) Die im Vergleich zu Erdgas vorteilhaften ökonomischen und technologischen Bedingungen für Kohle auf längere Sicht. (4) Eine gewisse Zögerlichkeit gegenüber erneuerbaren Energien seitens der Investoren. (5) Explizite politische Unterstützung für Kohle. (6) Mangelnder Erfolg öffentlicher Proteste gegen Bauvorhaben. Zwei dieser Gründe werden im Folgenden genauer untersucht.

Die zweite Untersuchung beschäftigt sich mit der Frage, wie die Allokation von Emissionszertifikaten Investitionen in fossile Technologien zugunsten von Kohle verzerrt hat. Der seit 2005 existierende EU Emissionshandel (EU ETS) wurde ins Leben gerufen, um Anreize für klimafreundlichere Investitionen mithilfe eines Preises auf CO_2 Emissionen zu schaffen. Allerdings wurden in der ersten Phase in Deutschland Zertifikate für neue Kraftwerke nach technologiespezifischen Maßgaben verteilt, was zu einer insgesamt deutlich höheren Zuweisung an Kohlekraftwerke im Vergleich zu Gaskraftwerken führte. Weil Investoren zusätzliche Profite (*windfall profits*) durch die Einpreisung der Opportunitätskosten der Zertifikate erzielen konnten war zu erwarten, dass Kohlekraftwerke deutlich höhere zusätzliche Einnahmen erzielen könnten, was einer Subvention dieser Technologie gleich kommt. Die Modellergebnisse der Untersuchung zeigen, dass ungleiche *windfall*

profits ungefähr die Hälfte der Kapitalkosten eines neuen Kohlekraftwerks gedeckt hätten. Nur eine Auktionierung der Zertifikate oder eine Zuweisung nach einem Benchmark der bestmöglichen Technologie hätten Gas zur bevorzugten Technologie werden lassen. Das unterstreicht, dass die Details der Implementierung des Instruments in diesem Fall einen großen Einfluss auf die Investitionsanreize hatten, und konträr zur Zielstellung dem Neubau von Kohlekraftwerken förderlich waren.

Die dritte Untersuchung abstrahiert von der Perspektive eines einzelnen Investors und beschäftigt sich damit, wie der Markt als Ganzes auf einen Preis auf CO_2 Emissionen reagiert, wenn durch den Kernenergieausstieg ein erheblicher Bedarf an Ersatzinvestitionen besteht. Im Detail werden sowohl die Technologiewahl als auch die Frage nach dem optimalen Preis von CO_2 unter Gesichtspunkten der Wohlfahrt betrachtet. Bedingt durch die Struktur des deutschen Markts, in dem vier große Erzeuger den Großteil der Kapazitäten besitzen, wird dabei unvollständiger Wettbewerb mit strategischem Verhalten dieser Erzeuger angenommen. Weiterhin wird angenommen, dass neue Kohlekraftwerke ausschließlich von eben diesen Erzeugern gebaut werden können, wie es in der Realität in den letzten Jahren auch zu beobachten war. Die Modellergebnisse zeigen, dass bei diesen Annahmen Investitionen in Gaskraftwerke schon bei niedrigeren CO_2 Preisen und insgesamt schrittweiser getätigt werden als bei perfektem Wettbewerb. Dies ist der Fall, weil die strategische Reduzierung der erzeugten Strommenge zu höheren Preisen führt, wodurch Gaskraftwerke auch bei geringeren komparativen Kostenvorteilen bezüglich der Emissionen schon profitabel sind. Im Gegensatz dazu erfolgt bei perfektem Wettbewerb ein strikter Bruch in der Technologiewahl. Bei einem Preis von 36 EUR/t oder weniger wird ausschließlich in Kohle investiert, ab einem Preis von 37 EUR/t oder höher ausschließlich in Gas. Unter Gesichtspunkten der Wohlfahrt allerdings spielt dieses deutlich unterschiedliche Verhalten kaum eine Rolle, denn die Verluste durch Marktmacht sind kleiner als 1% wenn der CO_2 Preis optimal gesetzt wird. Das unterstreicht, dass ein Preis auf CO_2 Emissionen in der Tat ein geeignetes Instrument sein kann, um Anreize für Investitionen in klimafreundliche Technologien - insbesondere Erdgas - zu schaffen. Allerdings bleibt abzuwarten, ob die für einen fundamentalen Umbau benötigten hohen Preise in der Zukunft auch tatsächlich verwirklicht werden.

Chapter 1

Introduction

In the last two decades electricity sectors in many countries underwent a fundamental change from regulation to liberalization. As a consequence, the new economic environments have shifted business operations from planning to strategies (Dyner & Larsen 2001), which are essentially determined by the rules of the market. Given the by now lack of central coordination, one of the most important contingencies of deregulation is if the market can indeed provide the economic efficiency for which it had been advocated in the first place. This especially pertains to investments in new capacity, which due to the long time horizons and high risks involved crucially depend on a properly functioning market. At the same time, the political priority put on sustainability requires a transformation of energy supply towards a lower carbon intensity. Here again, investments are a key figure because they determine the structure of energy supply in the mid and long run, and stimulate respective technological innovation. Accordingly, political mechanisms are needed to incentivize "cleaner" technologies in accordance with the incentives originally provided by the market. This interplay has only begun to unfold, and there are still many unresolved questions regarding its success and efficiency.

This thesis addresses this issue with a case study of the German electricity market, where current investments trends have led to a broad discussion of market responds to the new situation. In order to provide a comprehensive picture, Section 1.1 describes the essential role of power supply in tackling climate change and outlines two important preconditions that have to be taken into account when transforming it. Based on this, Section 1.2 elaborates the involved problem dimensions on a more detailed level, providing the general background for succeeding chapters. Finally, Section 1.3 puts the German case into perspective and establishes the detailed research questions of this thesis.

1.1. Climate Change & Power Supply

In the context of power sectors, achieving sustainability is usually associated with transforming electricity supply towards a low-carbon generation to tackle global warming. The need to do so arises from the danger that lurks behind rising global mean temperatures, namely climate change, which has been recognized as a large-scale threat to humanity within the last four decades[1]. The understanding of its impacts has constantly sharpened public awareness, and reports by Stern (2007) and the IPPC (2007) – to name but the most important ones – have eventually made it a top priority on many political agendas. As a consequence, a lot of societal resources have been dedicated to identify options to adapt to or mitigate its effects. Regarding the latter, the greenhouse effect as the actual cause of global warming dictates the reduction of anthropogenic greenhouse gas (GHG) emissions. This is where electricity comes into play: a large share of all emissions worldwide originate from fossil-fuel power generation for which the GHG carbon dioxide (CO_2) is an unavoidable byproduct[2]. With a primarily technological perspective on this problem[3], the overall strategy must thus call to replace fossil energies with renewable energy sources (RES) in this process. A main pathway for doing so is the potential availability of many low-cost RES alternatives to substitute fossil fuels in the

[1] For a short overview see Monastersky (2009).
[2] In 2007 the power sector accounted for around 41% of all energy-related CO_2 emissions ((IEA 2009).
[3] It should be acknowledged that some people claim that a pure technical solution is a kind of false promise distracting from a required reduction of consumption; see for example Blühdorn (2010).

long-run implying fundamental *technological change* (e.g. Ford 2008). Modeling results so far indicate that total consumption losses arising from this transformation are at a relatively low level; see for example Clarke et al. (2008) and Pizer & Popp (2008) for modeling assumptions, and Edenhofer et al. (2009) for modeling results. Thus from a technological perspective, straightforward promotion of RES lies at hand – and for good reasons is advocated all around. However, this transition is a great challenge, and the remainder of this section will give a short overview why.

First of all the world needs power. Even though large parts of the world population still have non-industrial lifestyles or forsake electricity for some reasons[4], its important role for global energy supply and economic output is obvious. As Figure 1.1. shows, world electricity consumption has increased 243% between 1971 and 2005. At the same time, global GDP has grown with a lower rate amounting to a total of 182%, while primary energy supply only increased 106%. Thus there is a relatively stable development pattern towards a lower energy intensity, but higher electricity intensity of economic output. Even during times of economic crises electricity consumption has grown steadily each year, with the global credit crunch in 2009 being the first exception since the end of World War II (IEA 2009). Thus it is clear that in order to drive and sustain economic growth, in particular industrialized countries have a high interest to secure their supply of electricity. Regarding a transition towards large shares of RES the main controversy is arguably how to replace conventional technologies without risking supply stability and security. Especially for intermittent energy sources like wind and solar, which in general do not match traditional demand patterns, integration into current energy supply systems remains a crucial issue (IPCC, forthcoming).

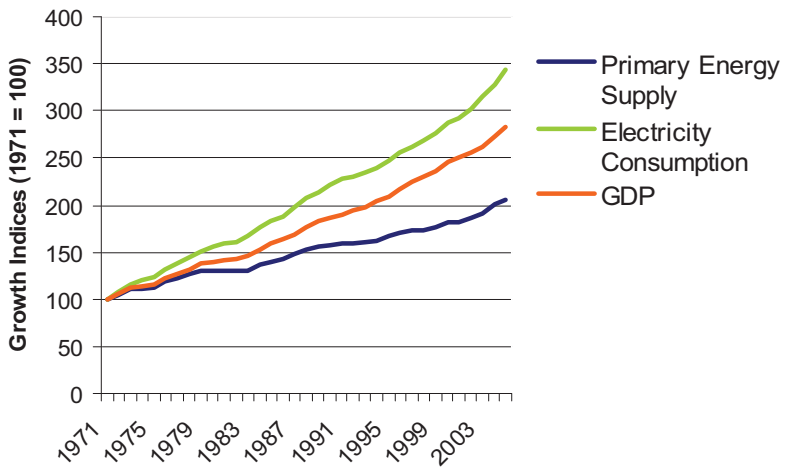

Figure 1.1: Selected World Growth Indices (Source: IEA Databases)

A second issue is that power generation exhibits *economies of scale* – average costs decrease with increasing output – and thus constitutes a *natural monopoly* (Stoft 2002). This has fundamentally shaped the evolution of electricity sectors in many ways. More

[4] According to Amish views for example, especially the easy access to electricity may lead to temptations and deterioration of church and family life (Scott & Pellmann 1990).

precisely, governments combined sector regulation and central planning from early on in order to secure supply at low costs. This is documented for example by Hughes (1993) and Brandt (2006) for western societies, and Coopersmith (1993) for the Soviet Union. Unruh (2000) points out the continuous reliance on fossil fuels thereby and how it manifests itself through combined interactions among technological systems and governing institutions. By the same token, deployment of new technologies was often enforced as part of national energy policies. A very prominent case is nuclear power, which was brought on the way with extensive political support; see for example the accounts of Hecht (2009) for France, Radkau (1983) for Germany, and Wildi (2003) for Switzerland. More comprehensive historical accounts are found in Munson (2005) and Patterson (1999), which support the following generalized findings: (a) Governments have regulated electricity sectors in order to secure supply and exploit economies of scale. (b) Governments had a perpetual and strong influence on technology choice. (c) Power systems "have been locked into fossil fuel-based energy systems through a process of technological and institutional co-evolution driven by path-dependent increasing returns to scale" (Unruh 2000). This carbon lock-in is now seen as a main barrier for large scale deployment of RES[5].

Notwithstanding security of supply and carbon lock-in, one could argue that political action could promote RES now as it did with nuclear or coal in the past – except that the recent liberalization of electricity sectors in many countries has put an end to immediate political influence. In the 1970s to 1980s concerns about regulation grew steadily and finally culminated in initiation of reforms in key countries. The main driver was the promise of cost efficiency – in the short and long run. Guthrie (2006) reviews the fundamental problems concerning regulation of infrastructure and respective investments, which can go as far as regulatory opportunism (Lyon & Mayo 2005). Moreover, Graves & Baker (2005) compile the numerous disincentives for investment under regulation that exist. It was mainly due to these inefficiencies that proponents of deregulation raised their voices. The most prominent case was the US under Presidents Carter and Reagan, for which the seminal study of Joskow & Schmalensee (1983) names several arguments in favor of liberalization. First of all, prices to consumers were rising steadily, but on the other side were not high enough to recover capital expenditures of the industry. Moreover, the sector had not been able to take advantage of all available technologies, in particular emerging ones like cogeneration, small-scale hydro and RES. The authors review arguments pointing out that both failures were attributed to the imperfections of regulatory arrangements and the "insulation from the discipline of the marketplace". Another important case is the European Union, where many member states were actually not inclined to deregulate the sector. However, political momentum mainly from the UK Thatcher regime strongly advocated liberalization within the Commission (Nylander 2001). Under British lead market supporters eventually paved the way to create the internal market for electricity backed by similar arguments as used by their US

[5] Based on a historical analysis of the US electricity market Carley (2011) argues that this barrier may be less severe than initially assumed. However, it remains to be seen whether the industry is able to transform entirely and early enough.

counterparts. The liberal twins US and UK had thus initiated a still ongoing worldwide liberalization of power sectors, which fundamentally changed the rules of the game[6].

Today the liberalization of most industrialized power sectors has been enacted and markets are changing gradually in response to the new regimes[7]. The outcomes of reforms are still unclear though; for current states see for example the studies in Siosahnsi & Pfaffenberger (2006) and Sioshansi (2008), and the overview of problems by Wilson (2002). But, as will be shown below, a properly functioning market is seen as the most important device to accomplish the low-carbon transition by many policy makers. First experiences if markets and particular designs have worked well are ambiguous though; cp. Beneyto (2010). On one side the Pennsylvania-New Jersey-Maryland (PJM) market in the US is often named as a positive example for keeping the promise of efficiency. Likewise, the north European Nordpool market has also performed quite well. On the other side, some schemes have clearly failed: in California design flaws have led to a great crisis in 2001 as documented by Sweeney (2002). For the UK, Thomas (2006b) claims that the so called "British Model" had failed, mainly due to a not properly developed wholesale marketplace lacking both liquidity and unrestricted access. Moreover, Woo et al. (2003) point out the negative influence of market power in several countries. The distinct outcomes of liberalizations have motivated comparative studies trying to identify reasons; see for example Thomas (2006a) and Hadjilambrinos (2005) for a comparison of Britain and Norway/Nordpool. They find that the particular generation mix and the adherence to public ownership instead of privatization played an important role for the success of latter and the failure of the former model. On a more general level, they conclude that the socio-political dimensions underlying and shaping the reforms are a crucially important factor. Notwithstanding early experiences whatsoever, the major challenge for liberalized markets is to provide appropriate capacity in the long run. And in this regard the success of reforms is still unproven.

Coming back to the low-carbon energy transition, political action to combat climate change hit power sectors just amidst the turmoil of liberalization. As mentioned above, where previously regulating authorities could have commanded adoption of low-carbon technologies, the new situation leaves the market to its own devices. The main implication is the use of market-based instruments, which is coherent with the above described primate of efficiency. However, there is little historical experience using such instruments in energy sectors and broad concerns about the prospects of managing the low-carbon transition in such a way exist. Jørgensen (2005) for example terms the current situation as "technologies and regulatory policies in flux" and points out several limitations of market-based instruments in providing the needed transition. Lévêque (2006) and Polasky (2004) address the same question, namely how to incentivize sustainability in competitive electricity markets. More general accounts including historical perspectives are provided by Patterson (1999) and Munson (2005). The common theme to all is the challenge in this task, or in the words of Moss & Kwoka

[6] The US and UK (generation) sectors were also among the first to be finally liberalized in 1979/1992 and 1990 respectively (IEA 2005).

[7] In fact a comprehensive deregulation including the creation of a market only applies to generation. Transmission and distribution are still regulated.

(2010): "The transition to a low-carbon, efficient electricity industry will be nothing short of a revolution." In any case, the key to this transition are investments in new capacity in the near future, which shape the energy systems for the coming decades. The when and what of these investments are a central aspect of this thesis, to which it aims to contribute within a narrower focus.

1.2. Problem Dimensions

The previous section illustrated the important role of power supply in combating climate change and the difficult interactions with the recently liberalized sectors. This section aims at a further elaboration of the involved dimensions and their implications for investment. The general approach, in particular the choice of dimensions for analysis, follows the work by Joskow & Schmalensee (1983).

1.2.1. Political Dimension[8]

The political interests related to energy supply have already been touched above: *sustainability*, *competitiveness* and *security of supply*. This trinity of targets, sometimes called the *Strategic Triangle* (see Figure 1.2), has become – either explicitly or implicitly – the cornerstone of energy policies in most industrialized countries. In the following, the development and current state of these targets is discussed for the European Union (EU). This is a first step to narrow down the scope towards the case study of this thesis: Germany. In fact, EU legislation has been an essential driver for energy policies in its member states during the last decade. Moreover, taking EU policy as a showcase is helpful to illustrate issues and actions beyond a stylized level.

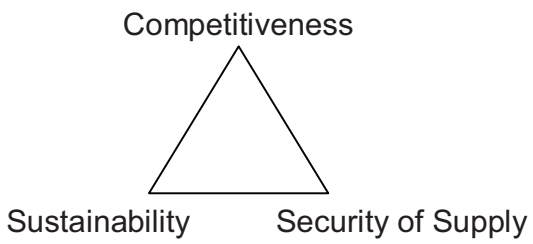

Figure 1.2: Strategic Triangle of Energy Policy

Until the mid 1980s energy had not been an essential part of EU integration, and member states – pursuing national interests – were generally seen as the main actors (Matlary 1997). This situation changed with the inception of the *Internal Energy Market* (IEM), originally presented by the Commission in 1988 (Nylander 2001). From then on, EU energy policy "developed markedly as an integral part of the internal market and beyond" (Matlary 1997) and in 1995 a Green Paper was presented that for the first time brought the three objectives together. Still, it required a shift of competences and increasing support of member states to install the EU as a major player in the field. A milestone was reached in 2006 with the pioneering Green Paper (EC 2006) outlining an energy strategy

[8] Joskow & Schmalensee use an „institutional dimension" instead, but I deem the focus on policy more appropriate here. Some aspects of institutions are also discussed as part of the "economic dimension".

based on the strategic triangle (Vinois 2007), which eventually lead to the 2007 Energy Package (Pointvogl 2009)[9]. As part of this development, several major policies were implemented that target electricity sectors and investments therein. To comprehend the political dimension a look at their states of legislation, rationales[10] and existing problems is required.

First and foremost rank the actions to liberalize and integrate the market. This process – organized around successive legislative energy packages – started with Directive 96/92/EC to be repealed by Directives 2003/54/EC and 2009/72/EC in the following[11]. In accordance with the general idea of liberalization, the Green Paper proclaims that a fully functioning market will boost competitiveness and provide the necessary price signals for investments. Being aware of the painstaking process to complete the IEM, the European Commission (EC) has issued annual benchmark reports to monitor progress[12]. It thus acts as a watchdog over implementation, in support of which an extensive sector inquiry was issued in 2007[13]. Investigations so far have established that a full implementation has not been achieved yet due to several obstacles (Meeus et al. 2005). Prominent among them is the high concentration in many markets, resulting from both non-divestiture of national monopolies as in France and waves of mergers and acquisitions as in Germany; see Thomas (2003), Domanico (2007), Verde (2008), Haas et al. (2006), and Weigt et al. (2009). In fact, concentration is probably the main downside of liberalization creating a threat to efficiency through potential market power, with impacts both on prices and investments[14]. Looking at Central Europe , Haas (2005) goes as far as calling a sufficiently large number of market participants a condition without which the final result of reforms will be considerably distorted again. As will be seen below, a functioning market is the vital element also for other targets – and thus a crucial determinant of success or failure of the EU's energy strategy.

Second, and in the focus of this thesis, important action happened in pursuit of sustainability, which for energy supply is usually associated with climate change and reduction of CO_2 emissions. The most important measure has been the implementation of a CO_2 emission trading scheme (EU ETS) in 2005 based on Directive 2003/87/EC[15]. By means of an EU-wide cap it limits emissions of selected industries, foremost the power sector; see Egenhofer (2007), Convery et al. (2008) and Ellerman et al. (2010) for overviews. According to the Green Paper (EC 2006) it creates a flexible and cost-efficient framework for climate friendly energy production, also enforcing the entry of RES technologies in the market. However, early allocation rules in some countries – notably Germany – had created perverse incentives through favoring investments in high-carbon technologies; cp. Åhman et al. (2007) and Schleich et al. (2009). In these cases suppliers were able to acquire windfalls profits by passing-through costs for

[9] For more recent overviews of EU Energy Policy see Geden & Fischer (2008) and Pollak et al. (2008).
[10] Based on the on the Green Paper.
[11] Subsequent changes were mainly related to accelerate market opening, network access and unbundling.
[12] Available online at http://ec.europa.eu/energy/gas_electricity/benchmarking_reports_en.htm
[13] Available online at http://ec.europa.eu/competition/sectors/energy/inquiry/index.html
[14] As a consequence, antitrust investigations like the suit against E.ON in 2008 are a necessary complement in the overall process.
[15] A major amendment was made by Directive 2009/29/EC.

grandfathered certificates; cp. Sijm et al. (2006). Even though the main short run effect – a fuel switch from coal to natural gas – has already been observed (Delarue et al. 2008), the long run effects on low-carbon investment and technology choice are largely unexplored yet. Here again, the promise is that the carbon price signal triggers investments into low-carbon technologies (EC 2006).

Among other things also motivated by the challenge to tackle climate change, the EU has persistently promoted and stipulated the increasing use of RES. However, up till now no particular instruments are in place, and action is limited to RES targets for energy shares to be met in 2010 (Directive 2001/77/EC) and 2020 (Directive 2009/28/EC) respectively. In contrast to emission trading, the EU has been reluctant to implement a harmonized tradable green certificate scheme, even though it had already established an appropriate framework[16]. Possible reasons for this include both the effectiveness of already existing national support schemes (Ragwitz et al. 2007) and caveats about possible flaws of such a scheme as for example raised by Jacobsson et al. (2009). In this respect a consistent application of market-based instruments has not been accomplished yet. The policies in place had relatively different impacts on investments and technology choice so far, like for example shown for the UK and Germany by Toke (2007). As already mentioned, there is little doubt about the effectiveness of RES support, especially feed-in tariffs. Still, long term efficiency through an efficient mixture of RES technologies can in no way be taken as given. In particular deployment of expensive technologies with high potential for learning effects may fall short in market-based frameworks due to the relatively short time horizons therein (Del Río González 2008).

Finally, security of supply remains, which is more difficult to analyze due to the number of concepts and time scales it involves; see Andrews (2005) and Hughes (2009) for general overviews, and Correljé & van der Linde (2006) and Lévêque et al. (2010) for European perspectives. In the scope of this work, it is narrowed down to the "adequate level of generation capacity" as defined in the relevant Directive 2005/89/EC. From this perspective a main driver for action is the urgent need to replace Europe's ageing infrastructure over the next decades, which requires considerable overall investments; see DG Energy (2010). Still, the EU has been rather impassive so far: it basically mandates member states to ensure the proper functioning of the market and diversify supply, in particular based on RES[17]. This may include certain measures like capacity markets, but in practice has only resulted in repeated calls for stable political boundary conditions in order to secure investments. Thus once again liberalization is invoked, implying that the proper market can trigger "timely and sustainable investments [by] giving the necessary price signals, incentives, regulatory stability and access to finance." (EC 2006). A viewpoint that is not exclusive to policy makers, but also supported by scientists like for example Glachant et al. (2008). In that sense security of supply is envisaged as a co-benefit of the implementation of the IEM.

In summary, the EU has placed high trust in the liberalization to achieve its targets in the field of energy policy. In one way or the other, the market itself or market-based

[16] The so called guarantees of origin were introduced as a certification mechanism in Directive 2001/77/EC.
[17] Thus RES deployment, by diversifying the energy mix, also contributes to security of supply.

instruments are meant to balance the goals appropriately, suggesting investors and suppliers to be the ultimate deliverer. However, as discussed above this approach imposes a number of problems, especially with regard to long term efficiency, investments and technology choice. The question remains if market actors indeed act as policies require and what measures are needed if not so.

1.2.2 Economic Dimension

In essence liberalization means two things for firms: risk and opportunity. On one side, participants in an unregulated market have incentives to improve efficiency in contrast to fixed rate-of-return or cost-of-service compensation (Joskow & Schmalensee 1983). On the other side, they have to act in an economic environment where many fundamental parameters are uncertain and where typical planning time scales are relatively long (15-20 years). It is this discrepancy that has changed the rules of the game in electricity sectors fundamentally.

Form the perspective of business decision making, Dyner & Larsen (2001) have characterized this as the change "from planning to strategy". At the heart of it are the uncertainties that emerge in a deregulated market (see Table 1.1). Utilities now face considerable price and demand fluctuations, and a regulator that may take a harder line with the deregulated industry. Moreover, market information becomes increasingly disclosed, and large industrial users like influential consumer groups may significantly increase competitive pressure. Evidently, this new situation requires very different mindsets and methods regarding decision making; cp. Hyman (2006). This represents a considerable organizational challenge, and there is anecdotal evidence that many firms still operate in traditional planning modes. In consequence, decisions may still not reflect the new realities, leading for example to a status-quo bias regarding investments as argued later in this thesis.

Planning input	Uncertainty in key planning input	
	Monopolistic market	Competitive market
Price	Low	Medium/High
Information	Low	High
Demand	Medium	High
Consumer choice	Low	Medium/High
Regulation	Low	High

Table 1.1: Planning Uncertainties (Source: Dyner & Larsen 2001)

All in all it is in making investments where the above described uncertainties have the highest economic impact – and a number of studies have analyzed this issue in response. A report by IEA (2003) is one of the most comprehensive, adding several investment-specific risks to the list compiled by Dyner & Larsen: (a) economy-wide factors like labour and capital availability, (b) generation mix diversity, (c) fuel prices and availability, (d) investment financing, and (e) CO_2 prices. When facing this many risks, business logic requires that the required rate of return must be sufficiently high in order to justify capital expenditure. In the power sector the overall project risk is essentially determined by the chosen technologies, which have distinct risk profiles making them

more or less attractive. A central factor are capital cost, which deter many investors from capital intensive technologies like coal or nuclear. However, circumvention of one risk often means exposure to another, for example volatile fuel prices in the case of less capital intensive natural gas capacity. Accordingly, choosing the right portfolio of technologies has become a main cornerstone of business strategies.

Given that risks influence investments so profoundly, the scientific literature has dealt with this issue extensively, foremost in the context of *investment under uncertainty* as coined by Dixit & Pindyck (1994). For instance, Blyth (2006) and Anderson (2007) have reviewed respective approaches pointing out the importance of *option values*. An option value arises if a currently high uncertainty can be resolved in the future, and indicates that delaying the project is worthwhile. Or, in the words of Ingersoll & Ross (1992), "every project competes with itself postponed" with the general effect that in the presence of high uncertainty the overall rate of investment decreases. In turn this requires a trade-off between remaining flexible and building only small chunks of capacity at a time on one side, and the advantage of large capacity additions through economies of scale on the other side (Dixit & Pindyck 1995). As in the case of technology diversification, larger investors have more options to develop appropriate strategies than smaller ones.

While the previous strand of research concentrates on the single investor taking the market as given, other approaches apply a wider scope leading to further viewpoints. First, larger suppliers may try to exert market power by influencing prices. Neuhoff & de Vries (2004) explain the preconditions and mechanisms, and point out the important consequence that new entrants – not knowing if high prices are due to market power or scarcity – may hesitate to enter the market. But they also make clear that if price risks are not covered, e.g. by long-term contracts, investment levels are reduced and technology choice is distorted. In that respect they alert to the practical difficulties of markets to provide incentives for efficient investment in contrast to theory. And second, competitors can mutually influence their behaviour (C. Weber 2005), especially in investment planning. For example Lambertz & Krahl (2007) mention that investment plans of big players are to a large extent foreseeable, which provides important market information, but may also discourage investments from competitors. Moreover, incumbents occupy existing sites, and new entrants often face the problem of finding alternatives; see Brunekreeft & Bauknecht (2006). As a whole strategic interactions on investment level have been scarcely analysed so far, and potential distortions to efficiency are still poorly understood.

The previous paragraphs have outlined that in response to the new regulatory environment utilities have changed their investment behaviours and adopted new strategies. Regarding the former, the years following liberalization have shown a trend towards less capital intensive technologies or, where firm size allowed it, diversification of generation portfolios. With respect to the latter, especially larger incumbents have reacted with concentration through *mergers & acquisitions* (M&A). The overall process in the European market is documented for example by Thomas (2003), Verde (2008), and Lévêque & Monturus (2008)[18]. The above discussion shows that there are several

[18] The survey by Leveque & Monturus lists 247 M&As between energy companies from 1998 to 2007.

advantages for firms to scale up: economies of scale, risk minimisation through diversification, and opportunity for strategic behaviour. However, this is condemned from the point of view of competition.

1.2.3 Technological Dimension

Investing in new capacity implies a choice of technology, which in a competitive market is primarily determined by expected profitability. To arrive at a decision, investors make use of scenarios to rank available alternatives, and in that respect anticipate future developments of prices, markets, regulation, and so on. This is absolutely essential because of the irreversibility of investments. In general plant lifetimes stretch over decades, and thus major deviations from the underlying scenarios constitute a considerable threat to profitability. As mentioned before it is this condition out of which the general tendency to invest in low capital intensive options or diversify over technologies arises. Nevertheless, there are many intricacies that continuously challenge the understanding of technology choice.

Experience with liberalized markets so far suggests that there are some patterns that are characteristic at least for the early stages. Most evident is the extensive addition of natural gas capacities within the first years of market opening in several countries (IEA 2005). Referred to as "dash for gas" in the context of the British case, especially new entrants had built plants at relatively low investment costs and low fuel prices at the time. Incumbents remained rather impassive at first, closing down inefficient plants in markets with initial overcapacities like in Germany (Brunekreeft & Bauknecht 2006). Still, increasing competitive pressure also affected large suppliers, especially where capital intensive technologies needed to prove profitability. Taylor (2008) for example describes the difficulties British Energy experienced with nuclear power when prices fell and falling cash flows lead to a serious financial crisis. On the whole, the new environment triggered a rethinking of the role of technologies in business activities (Markard et al. 2004). Whereas in regulated markets technical quality had been most important, liberalization switched priorities to cost reduction. In response, utilities have also increased their engagement in innovation activities in order to gain competitive advantages; see Table 1.2 for influences and possibilities under the different regimes.

	Monopolistic market	**Liberalized market**
Influence of consumers	Little or no direct influence on innovation processes; implicit mediation of customer preferences by public authorities	Increasing direct influence because of purchase decisions and a more intense communication
Influence of regulatory frame conditions	Various regulations in fields like security of supply, tariff setting or environmental protection; direct influence with regard to the introduction of new technologies like nuclear power or wind turbines	Regulation about prices and standard tariffs removed; other regulations (e.g. environmental measures) not affected by liberalization; new regulations in fields like consumer protection
Possibilities for replication / Possibilities for imitation	Diffusion of innovations coordinated by associations on the level of the sector, firms deliberately share their experiences and disseminate their knowledge; Replication (in its narrow sense) restricted to the area of supply of each utility	Diffusion not coordinated any more, Replication not locally restricted Firms try to obtain individual competitive advantages from their innovation activities; limited exchange of knowledge and information

Table 1.2: Innovation influences and possibilities (Source: Markard et al. 2004)

Despite a general increase of innovation, utilities do not necessarily show similar behavior with respect to the adoption of new RES technologies. The reason is that fossil power has dominated supply all along, and respective products have reached a high degree of maturity allowing operation at relatively low costs and risks. Accordingly, utilities adhere to fossil generation and established know-how. Referring to the carbon lock-in, Unruh (2000) points out the inhibition of carbon-saving alternatives, mainly because they could make present products and competences obsolete. However, in order to combat climate change the transition of generation towards low-carbon intensity is a must. In face of reluctant adoption by firms and with deregulated markets in place, policy makers must enforce appropriate choices by means of instruments – either by carbon pricing or by explicitly supporting renewables. Yet the widespread use of such instruments based on a market mechanism has been unprecedented[19]. Hence it remains to be seen if the market can be regulated using according instruments so as to choose technologies that accomplish the low-carbon energy transition.

A closer look at the policy objectives related to the energy transition reveals that the problem is actually twofold. On one side, there is the need to reduce carbon emissions of existing generation mixes and technologies through a *market push*. Action is thus short term, and comprises a *fuel switch* to lower carbon intensive fossil fuels, i.e. from coal to natural gas, and *efficiency improvement* in order to reduce fuel usage. In the EU for example, fuel switches and efficiency improvements reduced about 20% of the projected baseline CO_2 emissions between 1990 and 2004 (EEA 2008)[20]. On the other side, ambitious future targets will require a fundamental restructuring of the generation mix through a *technology push*[21]. Hence in the long run the *innovation & diffusion* of RES must be fostered in order to significantly increase their market share. A main difficulty are *innovation spillovers*, which are beneficial for society but go to the expense of innovators. Jaffe et al. (2005) name this "the tale of two market failures", expressing the environmental and technological part of the problem. This situation gives rise to one of the most highly debated policy questions in this field at the time, namely the optimal set of instruments that is needed to reach the envisioned goals. Arguments are drawn from stylized economic analysis and empirical evidence, and are presented in the following.

A review of recent analytical research on *regulatory uncertainty* shows that findings are ambiguous, especially regarding incentives for innovation and particular technology choice. Hepburn (2006) surveys available instruments with a focus on market based mechanism, i.e. carbon taxes and tradable permits. He concludes, mainly drawing on the work of Baldursson & von der Fehr (2004), that the higher price risks of permits appear to reduce investment in long-term research and development into abatement. Newell et al. (2005) though point out how permit schemes could be modified to "mimic the behavior of price policies" and thus outweigh potential disadvantages. In contrast Krysiak (2008)

[19] The US Acid Rain Program to cap sulphur dioxide emissions is the only comparable instrument for which sufficient experience is available so far. But due to the specific circumstances of its implementation the transferability of such a scheme is all but proven.
[20] This happened without an instrument in place and rather as a result of modernization and competition.
[21] In the context of instruments the *sticks & carrots* metaphor is also widely used.

demonstrates that under a tax scheme and cost uncertainty firms value output flexibility, and by choosing appropriate technologies firms can undermine expected social benefits and thus reduce total abatement quantity to suboptimal level. Starting from a hybrid instrument combining tradable permits with price floors and caps, also Weber & Neuhoff (2010) show that in the presence of innovation the optimal instrument converges to a pure permit scheme. Other studies explicitly integrate R&D and permit markets to investigate distortions through interdependencies. Requate (2005) finds that in case of a monopolistic firm engaging in R&D with unknown success, an ex-ante commitment to a menu of taxes dominates all other policy regimes. Montero (2002), in a study including both a permit and output market with different structures, shows that standards offer greater R&D incentives than permits if markets are oligopolistic. On a more general level, Del Río González (2008) argues that any incentive-based mechanism alone will not be sufficient for adoption of currently expensive abatement technologies, and that additional R&D policies are needed. Fischer et al. (2003) find that there is no unambiguous case for any particular instrument, and the ranking depends on several factors like costs of innovation, extent to imitate innovation, and number of firms. And finally, Fischer & Newell (2008) demonstrate that in order to achieve an optimal outcome, a whole portfolio of instruments is needed. In summary, there are arguments for one or the other policy, but due to every model's partial perspective there is no robust recommendation. Rather one can conclude that a mix of policies appears most promising, in the sense that "a long-term view suggests a strategy of experimenting with policy approaches and systematically evaluating their success" (Jaffe et al. 2005).

In that sense one should turn to empirical evidence, where the current instrument for CO_2 pricing, i.e. the EU ETS, seems to be capable of delivering technological change only piecewise, thus supporting the argumentation of Del Río González (2008). In an early analysis of the EU ETS Reimbaud (2003) already demonstrated that carbon prices must reach a very high level in order to make RES competitive. For Germany Hoffmann (2007) and Rogge et al. (2011) find that the innovation impact has been limited, and that the EU ETS may not provide sufficient incentives to reach envisaged long term targets. The only tangible outcome so far appears to be the development and deployment of CCS; for example DB Research (2008) presumes that this is the main policy objective. Indeed the EU ETS is widely assumed to create the main incentives for adoption (Kavouridis & Koukouzas 2008). Regarding the push of RES technologies, every EU member state operates an independent regime that is either built on market based approaches like tradable green certificates or direct subsidies like feed-in tariffs. In a comparative study of the UK and Germany, Toke (2007) finds that the UK certificate scheme poses higher risks and induces less investment than its German feed-in tariff counterpart. This is confirmed by a comprehensive study of all national EU support schemes (Ragwitz et al. 2007), which also identifies feed-in tariffs as the most effective instruments. This suggests that RES – at least at this stage – need an economic niche to thrive, and market based schemes for neither CO_2 nor RES certificates create a sufficient stimulus. This has important consequences for both the RES investment activities and interactions with conventional technologies, which will be explained in more detail below.

1.3. The German Case

Even though the previous sections have highlighted that the transformation to a low carbon power mix is mainly rooted in political action on the European level, implementation is still country specific for several reasons. First, EU measures in general only provide frameworks, leaving member states some discretion for transposition into national law. Notwithstanding an increasing harmonization, national sectors still show considerable differences regarding regulation and instrument application. Second, RES support schemes are still in member state responsibility, and thus produce specific outcomes and interactions with the power market. Third, market liberalization also still differs to a large extent, from high levels of competitiveness as in the UK and Norway to very low levels like in Greece and France. Hence a market based analysis is only applicable in some cases. Moreover, integration of markets is still far from accomplished, and thus member state sectors are more or less isolated. Accordingly, generation and investments are still mainly driven by national considerations. And finally fourth, technology mixes and plant age structures vary largely resulting in particular preconditions to promote green investments. Especially in countries where infrastructure is overaged and largely fossil based, the necessity to replace old capacities creates an eminent case to investigate and analyze political action and market responses to enforce the low-carbon transition.

Against this background Germany is well suited for a detailed case study. Its long history and successful promotion of RES[22] has led to one of the highest rates of deployment in Europe during the last decade. Between 1990 and 2009 installed non-hydro capacity increased from 0.6 GW to 41.5 GW, with wind alone contributing around 26 GW (BMU 2010). As mentioned above, the main instrument in that regard has been a feed-in tariff (EEG) that intents to fully cover installation and operation costs plus a guaranteed return on investment. Hence RES investments were not induced according to the laws of the power market, but purely out of financial considerations. Nevertheless, RES generation contributes to overall power supply, and the resulting residual demand is now an important factor for operation and investment in conventional technologies. The details of this interaction are highly relevant for the question of how both types of technologies can co-evolve without risking security of supply and overly high costs, and thus call for further analysis. This is all the more important in face of the pending replacements of substantial conventional capacities. On one side, German fossil plants are relatively overaged approaching the end of their lifetime. The last investment boom goes back to 1970s (Lambertz & Krahl 2007), and as of 2008 around 67% or 51 GW have been in operation for 20 years or longer (Kjärstad & Johnsson 2007). Furthermore, in 2002 the German Government decreed the phase out of nuclear energy, which enforced the closure of around 22 GW of additional capacity until 2022. Even though this is currently in the process of being revoked, it nevertheless created the expectation of additional needs for replacement in the last years when it was not yet at stake. For these reasons – high RES share and extensive replacement requirements – Germany is a showcase for questions that arise in face of the low-carbon transformation of power supply.

[22] For overviews see Agnoluci (2006), Jacobsson & Lauber (2006), Lauber & Metz (2006), and Büsgen & Dürrschmidt (2009).

In fact, a particular striking outcome has already been observed during the last years: extensive planning and construction of new coal power plants. Around 26 GW of new projects are envisaged for the period 2008-2016, which amounts to around one third of the peak demand in 2007 (BNetzA 2008). This situation has received broad media attention and stimulated a controversial political debate that still persists. In particular with Germany's leadership role in climate policy in mind, many stakeholders wondered how and why investors "turned back" to coal in such extent. Comprehensive investigations are relatively sparse so far, even in the scientific literature. An analysis of the EU ETS by Ellerman et al. (2010) for example infers that the main reason behind this development had been the high natural gas price at the time, and that the EU ETS allocation rules might have given a further impetus at best. But they neither consider the comprehensive factors and drivers of investment decisions, nor do they provide a quantitative analysis of how new entrant allocations may have distorted investment decisions towards coal. Even more so, they do not consider the influence of market power on investments and how it may affect the optimal price of carbon.

In face of this "dash for coal" in Germany and the lack of scientific work to explain its drivers and rationales, this thesis addresses the following specific questions in the wider scope of investments in liberalized electricity markets and the low-carbon transition:

1. **In face of ambitious climate policy and respective instruments implemented: why are there so many new coal plants currently under construction in Germany? (Chapter 2)**

2. **To which extent have national allocation rules of the EU ETS contributed to the failure to induce cleaner investments in Germany? (Chapter 3)**

3. **How can the "dash for coal" be explained from a full market perspective? More generally, how do imperfectly competitive markets affect technology choice and optimal carbon pricing? (Chapter 4)**

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Chapter 2

Germany's dash for coal: Exploring drivers and factors*

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Germany's dash for coal: Exploring drivers and factors

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ABSTRACT

The German electricity sector has recently seen extensive planning and construction of new coal-fired power plants. Within a period of only a few years, new investments amounting to around 15% of the total sector capacity were brought on the way, and plans for a multitude of additional projects are pending. This 'dash for coal' in Germany has raised considerable public concern, especially as it risks to undermine recent political attempts to combat global warming. Yet, the question of why the dash for coal has emerged has not yet been addressed in a thorough analysis. This article attempts to close this research gap, while at the same time contributing as a case study to the general understanding of investment patterns in liberalized electricity markets. It finds that the main reasons for the dash have been (1) replacement requirements due to the nuclear phase out, (2) the onset of a new investment cycle in the power market, (3) favorable economic and technological prospects for coal compared with natural gas in the long run, (4) a status-quo bias of investors in regard to future renewable deployment, (5) explicit political support for coal, and (6) the ineffectiveness of public protest in hampering new projects.

1. Introduction

In recent years the European electricity sectors have experienced an increasing influence of the political and societal developments evolving around climate change. New instruments and regulations were introduced to initiate a transition to a less carbon intensive energy system, very often backed up by a broad public debate that demanded early action. Germany, with its strong tradition in environmental protection, can certainly be named as one of the EU member states at the forefront of this process.

Against this background the current extensive investments in new coal power plants in the country may surprise at first glance. As of 2009 ten plants with a total capacity of 11.3 GW are under construction (BUND, 2009), and if planned projects are included this number extends to around 30 GW and more, which equals approximately 40% of the peak electricity demand in 2007 (see BnetzA, 2008). Even for sector experts this turnaround in technology choice[1] has been largely unexpected, as it seemed completely out of time only several years ago (Brunekreeft and Bauknecht, 2006). Accordingly this trend, which in part is also a global one, has created some confusion both about its causes and persistence under the above described developments. Is there indeed a new 'dash' for coal that will shape the energy systems for the next decades, or is this just a minor boom that will soon fade away in a new era of green energy supply? The controversy of this issue is also acknowledged by the research community, as several titles demonstrate, e.g. 'The Rush to Coal: Is the Analysis Complete?' (Hamm and Borison, 2008), 'Future of Coal: Rhetoric vs. Reality' (Sioshansi 2009), and 'Coal: Hype or Reality?' (Capgemini, 2008). However, analyses so far have been rather superficial and especially short in explanations and exploration of potential causes.

Motivated by this shortcoming the central intention of this article is to identify and explore the drivers and factors that may have given rise to the revival of coal in Germany. Being a case study the underlying method can be classified as a qualitative analysis which tries to establish 'causes-of-effects' (see Mahoney and Goertz, 2006), with the effect under scrutiny being the observed trend for coal. It follows from the methodological restrictions that insights are limited to exploration of potential causes and hypothesis building, but do not allow a decision on necessary or sufficient conditions or generalization. Nevertheless, this article presents a broad overview which reveals previously unaccounted interdependences and perspectives.

A central difficulty faced thereby is the lack of a proper integrated theory of technology choice in liberalized electricity markets. On one side, the main drivers of investment in restructured markets are still unknown (Murphy and Smeers, 2005). On the other side decision factors, i.e. the determinants of technology choice once a new investment has been decided on, are only well defined within economic theory. But this approach is

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[1] In this context 'technology' and 'fuel' are used synonymously in the sense that one technology generates electricity with only one type of fuel.

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only partial and neglects relevant influences, as will be argued in this article. Therefore the identification of drivers and factors within this analysis can be seen as a scientific contribution by itself.

The article is structured as follows: Section 2 reviews investments in generation capacity in Germany over the last decades. It describes the development of the technology mix, including a preliminary identification of patterns that guide technology choice. Moreover, data of new plants currently under construction or planned are presented and discussed in order to make the trend for coal evident and put it on a solid factual basis. Section 3 compiles drivers and decision factors from the literature and the previous findings, and explores how they pertain to the situation. Section 4 shows under which constellations and relative importance of drivers and factors the current situation is a plausible outcome, and what this implies for the future.

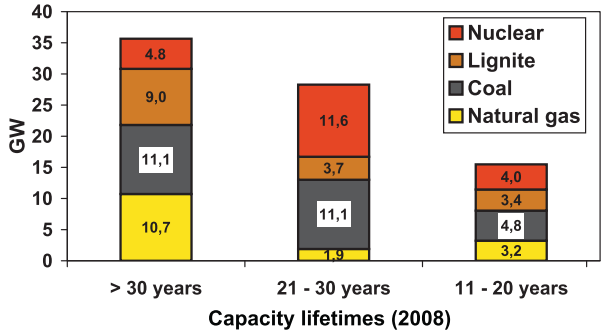

Fig. 1. Age structure of German fossil and nuclear power plants.
Source: Kjärstad and Johnsson (2007).

2. Investments in generation capacity

In this section data of historic and recent investments in generation capacity are presented and discussed. Even though the focus is on current technology choice, the long average lifetimes of power plants together with the industry around it have created lock-ins by which past actions determine present and future ones (Unruh, 2000). As will later be outlined, investments trends both in the 1970–1980s and the decade following liberalization in 1998 have played a considerable role in the recent revival of coal. The latter period will be described in more detail, because liberalization fundamentally changed the rules guiding investments and opened up the market for new players. In the course of events diverse groups of investors emerged, which for a number of reasons had a bias for one technology or the other. So as a relevant dimension regarding technology choice the type of investor will be accounted for.

Furthermore, taking the decision to build new capacity as given, the question arises in this context which technologies would have offered an alternative to coal. Coal power plants in Germany typically supply base (lignite) or intermediate (hard coal) load, and alternative options should possess similar technological and economic characteristics.[2] So only nuclear or natural gas can thus be considered as suited, depending on the envisaged operating scenario. Since the phase out of nuclear power has been decided in 2002, possible choices narrow down to a single alternative: natural gas. Below, this technology will be employed for counterfactual argumentation, i.e. to contrast the dash for coal against a possible 'dash for gas' that never materialized. Other technologies, in particular renewables, are taken account of only as additional boundary conditions for fossil plant operation and profitability. This is mainly justified by their lack of techno-economic characteristics required to make them an appropriate substitute for coal: large-scale centralized deployment, regional availability and non-intermittent generation. Respective arguments are described in more detail throughout Section 3.

2.1. Historic investments

As argued current investment trends in Germany are still influenced by the historical development of the sector, documented for example in Hilmes and Kuhnhenne (2006), Matthes (2000), and Brunekreeft and Bauknecht (2006). Until the 1960s power generation was nearly completely based on the domestic resources hard coal and lignite. In the first years of the 1970s oil and natural gas amended the generation mix, but the oil crises and rising prices switched priorities back to coal. The 1970s saw the last large investment boom in conventional fossil power plants in Germany so far (Lambertz and Krahl, 2007). At the same time, the newly developed nuclear technology emerged and dominated power sector investments until the early 1980s. While the 1986 Tchernobyl incident practically brought an end to nuclear power in Germany, the reunification in 1990 opened up new opportunities, namely the replacement or refurbishment of old lignite plants by Western integrated suppliers, and the entry of the newly founded Eastern municipal utilities into the market. For the bigger part the new utilities relied on natural gas that had become more attractive after the political situation had changed and access to the Russian resources was more readily available. These developments reflect themselves in the age structure of German power plants (Fig. 1).

2.2. Investments in the newly liberalized market (2001–2008)

With the liberalization of the national power sector in 1998 investment trends passed a turning point. Brunekreeft and Twelemann (2004) point out that '[t]he combination of the traditional model of cost-based regulation, incentives to invest in new capital and an obligation to guarantee a reasonable supply security, [had] created severe excess generation capacity in the German ESI [Electricity Supply Industry].' With electricity prices reaching a historic low and even temporarily falling below generation costs in 2000 (Lambertz, 2006), the large integrated suppliers (IS) in particular closed down old and inefficient plants (Brunekreeft and Twelemann, 2004). Even though prices started to rise again from then on, they were sending only tentative signals for new investments. Between 2001 and 2008 only 7.4 GW of new fossil fired capacity were build (Fig. 2). The predominant part of it (5.5 GW) was natural gas combined-cycle gas turbines (CCGT), seen as basically the only option for new plants for several years after liberalization (Brunekreeft and Bauknecht, 2006). Lignite accounted for around 1.6 GW, and hard coal hardly played a role at all.

Regarding the type of investor coal power plants were exclusively build by an IS or joint ventures with IS majority. In fact, the entire lignite capacity addition stems from the retrofit (2002) and an additional generating unit (2008) of a single plant (Nierderaußem /RWE). Natural gas plants, in contrast, were built by all the various players in the German electricity market:

[2] This implies that these factors essentially influence technology choice – for now a working hypothesis which will be dealt with more thoroughly in the next section.

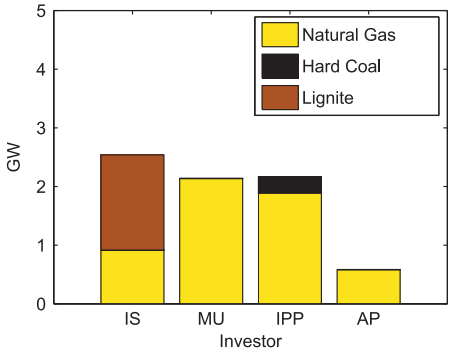

Fig. 2. Fossil power plants commissioned 2001–2008.
Source: BDEW (2007), UBA (2009a).

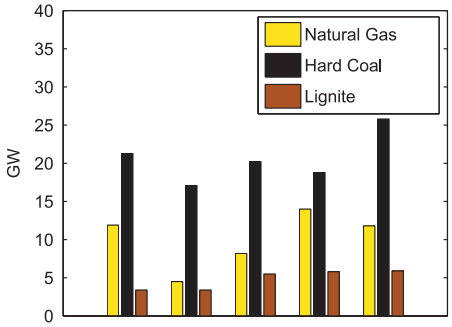

Fig. 3. Fossil power plants planned or in construction.
Source: Schmitz (2007), BNetzA (2007), BNetzA (2008), BNetzA (2009), UBA (2009b).

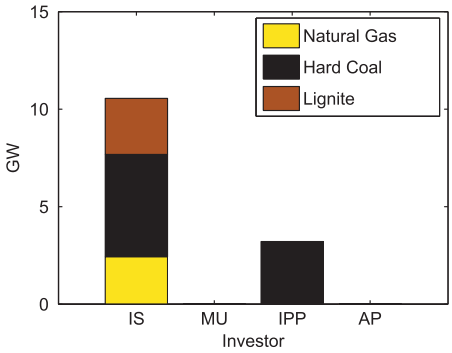

Fig. 4. Fossil power plants under construction.
Source: DENA (2008), Hilmes (2009), BUND (2009).

integrated suppliers (IS), independent power producers (IPP),[3] municipal utilities (MU) and industrial autoproducers (AP). The largest investments were made by IPPs and MUs, but with different scopes and scales in both groups. A more detailed look at the data shows that most municipalities built smaller combined heat power (CHP) plants with capacities of 100 MW or less, whereas the IPPs mostly built larger plants between 425 and 850 MW. These projects – in total three plants all built in 2007 – comprised the only market entry of considerable size by a foreign generator (Statkraft/Norway) and a plant by Trianel, a joint-venture of municipal distributors and retailers.

Investments in the post-liberalization period were also backed up by political support. This became eminent for example during the first EU ETS period between 2005 and 2007, where a major part of the natural gas plants were scheduled to go online. As Matthes and Schafhausen (2008) report on allocation negotiations: '[natural gas plants] were very important from a political point of view as well as with regard to their positive impact on the environment and on competition [...]. [They] were a political priority, received special incentives (e.g. tax breaks) and were not to be endangered by restrictive allocation provisions for newly constructed plants.' One of these priorities was the exemption of natural gas for generating electricity from a fuel tax, which was extended to apply to those power plants that started operation at the end of 2007 (see EC, 2004). This indicates that political priorities and respective control have not ceased to exert influence on technology choice even in the liberalized regime. The degree to which this plays a role remains unresolved without further empirical research, but it certainly qualifies as a relevant factor under the methodological background of this analysis.

2.3. Current investments and plans

Only a few years later the situation had changed considerably. Referring to capacity planned or in construction (Fig. 3), natural gas as 'basically the only option' appears outdated and coal – once again – dominates investments. The bulk of projects are based on hard coal where capacities range from 17.1 GW to 25.8 GW. Projections for natural gas range from 4.5 to 14 GW and for lignite from 3.4 to 5.9 GW.

These data include projects in all stages from 'in study' to 'in construction or testphase'. As many projects were cancelled in the past it is unlikely that all of these plants, 25–43.5 GW in total, will eventually be built. Moreover, the variation between all sources included in Fig. 3, if not based on incomplete information available to the authors, also indicates the unsteadiness in current investment planning activities of the sector. Limited to power plants currently in construction or with very high probability to be built, numbers reduce significantly (Fig. 4); all plants are scheduled to go online in 2012 latest.

Technology shares now show a completely different picture compared with the 2001–2008 period: coal represents around 80% of all new capacity whereas natural gas falls back to 20%. Furthermore nearly all plants to be commissioned in the next years are projects of ISs, namely E.ON, RWE, Vattenfall, and EnBW. Exceptions are hard coal plants by STEAG/EVN (Duisburg-Walsum), Trianel (Lünen) and GDF SUEZ (Wilhelmshaven), and a natural gas plant by a joint-venture with E.ON majority. Concerning sizes, current projects are in the range of 0.5–0.9 GW (natural gas), 0.8–1.6 GW (hard coal), and 0.8–2.2 GW (lignite), without a single CHP unit. That is, the current period is mainly characterized by the domestic integrated suppliers building large centralized plants.

In the future the situation may be more diverse again, at least concerning the type of investor. According to planning data reported by Schmitz (2007), 28% of all new projects are run by IPPs or foreign players. However, some major problems remain that threaten this diversity, namely the difficulty of finding proper sites for new plants (Brunekreeft and Bauknecht, 2006) and the dominance of domestic players in the German electricity market. As Lambertz and Krahl (2007) point out, investment plans of the ISs are basically foreseeable for the next few years, which might well prevent new market entries. Moreover, in case of natural gas vertical integration also extends to supply infrastructure with potential negative side effects. In Lubmin for example, a project by a new IPP (Concord) was cancelled due to resistance by

[3] Foreign integrated suppliers are treated as IPP here.

supplier Gazprom, which in turn signed a declaration of intent with E.ON to realize the plant itself (Wirtschaftswoche, 12.01.2009).

A more detailed examination of the political influence on the current trend will be presented in the following section. But it should be made clear in advance that the existing concentration in the sector, i.e. the emergence of the integrated suppliers in their current form and size, resulted from political tolerance and even stipulation. In 1994 and 2000 politicians agreed on a number of mergers and acquisitions that considerably increased concentration – see Brunekreeft and Bauknecht (2006) for a detailed list. It will later become clearer that to a certain extent this has been a prerequisite of the current situation.

2.4. Investments since 2001 in comparison: trend and counter-trend

Investments since 2001 can be divided into two periods which significantly differ by type of investor and main technology employed. In the early years after liberalization a competitive fringe of municipal utilities and newly founded independent power producers emerged in the German power market. The technology of choice was natural gas then, with IPPs mostly building larger plants whereas MUs built smaller plants often generating CHP. The fact that natural gas prices were on a historic low in 1999 (see BMWi, 2009) can surely be seen as relevant. But to assert they were the sole driver probably falls short of the complex interplays involved. This is suggested by a similar case, namely the 'dash for gas' in the British electricity industry during the 1990s. As Winskel (2002) argues this dash was '[the] outcome of the interplay of previously excluded international forces with latent local interests, mediated by policymaking expediency [...] rather than [...] a result of technical and economic imperatives, or structural and regulatory reform.'

In contrast, the period after 2008 is characterized by more extensive capacity additions in a shorter time, namely 13.8 GW in 2009–2013 compared with 7.4 GW in 2001–2008. Most of the plants are hard coal fired, and domestic IS account for around 80% of all new capacities. So the new investments in coal cannot only be seen as a trend in itself but as a counter-trend to preceding years.

3. Exploring drivers and decision factors

In this section potential drivers and decision factors behind the dash for coal will be explored and discussed. A major obstacle thereby is the lack of an integrated theoretical foundation which ex-ante identifies the relevant categories – drivers and decision factors – and clarifies their relationships and causal dependencies. The approach described by Laurikka (2006) probably comes closest to such a framework, with its main strength in integrating organizational structure and decision making. However, it is dedicated to the effects of climate policy and accordingly restricted in the influential factors it accommodates.

The most clear cut approach so far is provided by economic theory, which states that capital and operation costs, broken down to levelized unit costs, are the determinants of technology choice. For descriptions see e.g. Stoft (2002) and IEA (2005); for an extension including risks and electricity price see Hyman et al. (2006) and Anderson (2007). This perspective provides the following decision criteria:

- Operating costs, in particular fuel and CO_2.
- Capital costs and financing.
- Market development (technological structure, demand, prices, operation).

Also of economic nature are location factors of sites for new plants. Reich and Benesch (2007) quantify respective costs for hard coal power plants in Germany and find considerable impacts on profitability. Moreover, efficiency improvements and new technological options like carbon capturing and storage (CCS) are an important strategic aspect for investments, potentially creating cost advantages in the long run. In fact, it is standard practice in the power sector that R&D is performed in pilot project cooperation with envisaged commercial operation. As such, a certain technology path can be actively pursued rather than seen as a future option that evolves exogenously, implying to be a determinant of technology choice. This puts a focus on:

- Location factors.
- Technological development, in particular thermal efficiency and CCS.

Finally, there is also a socio-political perspective on technology choice as for example pointed out by Hadjilambrinos (2000). In a comparative study he shows that these factors shaped the transitions in the energy system in France and Denmark following the first oil crisis. Political influence has also been testified in the last section for the case explored here. On the social level, public acceptance of a technology plays a role, which ranges from general disapproval to not-in-my-backyard (NIMBY) protest. In Germany especially coal – often termed 'Klimakiller' (*climate killer*) in the public – is affected and often local or regional authorities join in and hamper projects considerably, as a number of cancelled or delayed projects in the recent past have shown. Besides direct resistance there are potential collateral impacts on image and reputation on the respective investor. Gray and Balmer (1998) suggest that managers need to be concerned in this case, but they also point out that image and reputation are definitely not the only resources that confer marketplace advantages. Until now there is no research on the interaction of image and reputation and technology choice in energy companies. It is difficult to assess the relative importance, but the effects are visible and should not be neglected ex-ante. Eventually this adds[4]:

- Siting.
- Public acceptance.
- Political support.

In the following all of these dimensions will be explored under provision for being possible causes or ineffective hindrances of the observed trend for coal. Throughout this exploration, and in a final conclusion in Section 4, it will be argued how this trend could possibly be seen as a plausible outcome of the interplay of respective factors and drivers.

3.1. CO_2 emission costs and windfall profits (EU ETS)

The costs of CO_2 emissions suggest themselves as a starting point, because at first glance the trend for coal is a counter-intuitive outcome in particular under climate policy. Its single most important instrument, the EU Emission Trading Scheme (ETS), started in 2005 with a 'trial and learning phase' (2005–2007) and has now reached the second phase (2008–2012). A third phase will follow (2013–2020). With a lot of barriers to overcome in the beginning, the trading scheme only slowly reaches effective implementation. Above all, only a minor part of certificates has

[4] For comparison with risks compiled by an investor see Vattenfall (2008).

been auctioned during the first two periods. Accordingly the allocation mechanism, specified in national allocation plans (NAP), and its intricate details are of utmost relevance for new power plants. The German NAP I comprised the following relevant regulations regarding new entrants and closures (see DEHSt, 2005): (a) new installations receive free certificates according to projected emissions and limited by technology specific best available technology (BAT) benchmarks for the first 14 years of operation with ex-post corrections, ranging from a minimum of 365 kg/MWh to a maximum of 750 kg/MWh; (b) if old installations are replaced, the respective allocation – based on historic emissions – is transferred to the new installation for 4 years.

Taking into account that – as economic rationality suggests – opportunity costs for emissions certificates are passed-through to power prices, a free allocation for 14 years represents a valuable asset, even if pass-through rates are in fact lower than the full certificate price. Sijm et al. (2006) estimate rates between 60% (off-peak) and 100% (peak) for 2005 using power exchange data. A report by Point Carbon (2008) also assesses pass-through rates in Germany as high as 75–100%. Thus an extra stream of revenues is generated, which reduces both investment costs and risks (Hilmes and Kuhnhenne, 2006). Moreover, the BAT based discrimination between technologies does not provide an incentive for the more environmental friendly natural gas option. Rather it was the explicit intention of policy makers that the construction of new power plants should not be hampered by allocation rules (Matthes and Schafhausen, 2008).

This situation provoked broad criticism resulting in important revisions of NAP II in this regard[5]: (a) new plants receive an annual allocation of 365 kg/MWh (natural gas) and 750 kg/MWh (other technologies) multiplied by capacity and predefined full load hours, namely 7.500 h for natural gas and hard coal and 8.250 h for lignite; (b) free allocation are granted only for the duration of the second phase (2008–2012), i.e. for a maximum of 5 years. The former amendment can be seen as an explicit incentive for natural gas when compared with the factual load factor of this technology (see Section 3.4). Nevertheless, within the first two periods of the ETS allocation rules have set no priority on natural gas over coal. On the contrary, technology specific benchmarks combined with grandfathering have generated (existing plants) or offered (new plants) enormous rents for coal. This also holds for natural gas, but due to smaller allocations only to a lesser extent.[6] Accordingly, the ETS as implemented in the German NAP I and II has even provided additional incentives for coal. In fact, as an early comparison of NAPs for period II has shown (Neuhoff et al. 2006a), Germany has allotted the highest number of certificates for new coal power plants among ETS participants.[7]

From phase III on certificates will be fully auctioned, at least in Western European countries. Under such a regime costs for certificates will directly modify the cost structure according to carbon intensity thus adjusting incentives in favor of natural gas. The magnitude of this effect will clearly depend on the future price of emission certificates, which is subject to a number of uncertainties. A market survey by Point Carbon (2009) reports expectations for 2020 certificate (EUA) prices to peak at 30–50€, with around 85% of respondents estimating this price level or a lower one. Modeling results by IEA (2008) suggest 90$ and 180$ in 2030 for a 550 ppm and 450 ppm scenario, respectively. Such magnitudes are certain to have a significant impact (see Section 3.4). Still they must be related to fuel costs and technological options and will be picked up again.

Table 1
Coal and natural gas price scenarios.

Fuel	Scenario	Scope	Period	Price inc. (%)[a]
Hard coal	IEA (2007)	OECD	2006–2030	−2.7 to 15.6
	DG TREN (2007)	Europe	2005–2030	0.7
	WEC (2007)	Europe	2005–2035	40.3–59.7
	IEA (2008)	OECD	2007–2030	51.0
	EWI/EEFA (2008)	Germany	2005–2030	−4.3
Lignite	EWI/EEFA (2008)	Germany	2005–2030	0[b]
Natural gas	IEA (2007)	Europe	2006–2030	0.3–41.1
	DG TREN (2007)	Europe	2005–2030	38.0
	WEC (2007)	Europe	2005–2035	64.8–96.3
	IEA (2008)	Europe	2007–2030	101.9
	EWI/EEFA (2008)	Germany	2005–2030	−11.1 to 33.3

[a] Real prices (base year).
[b] Assumption.

3.2. Fuel costs

Another essential component of the cost structure is fuel costs, especially for natural gas plants. Several scenarios are available (see Table 1) that may well be used as an indicator of the respective price risks. Estimated price increases for 2030 and beyond are on average lower for hard coal than for natural gas. In particular every single scenario predicts higher prices for natural gas relative to hard coal in the future. The situation is quite different for lignite, for which there are no market prices and where extraction costs probably remain constant or only slightly increase in the future (Schiffer, 2008). Altogether this suggests that the already existing fuel cost discrepancy between coal and natural gas will further intensify. Moreover, there is much more uncertainty about future prices for natural gas than for hard coal, mainly because of the strong link to the oil price, which itself is exposed to a number of acute risks in forecasting (IEA, 2008).

Scenarios of central institutions like IEA or WEC certainly shape expectations of future trends, but they are no precise forecasts and are not meant to be.[8] So after all investors assessing economic profitability base their decisions upon proprietary scenarios that reflect specific supply contracts, market positions, generation portfolios and expectations about the future. This has been confirmed in an empirical study of investments of German generators during ETS phase I by Hoffmann (2007), who states that '[s]ince investment decisions highly depend on the underlying assumptions on fuel price, government policy, and allowance cost scenarios, different companies come to different conclusions which technology may fit best to their current portfolios.' As Hoffmann further confirms, conservative gas price scenarios and high CO_2 price assumptions have favored investment in natural gas power plants, whereas increasing natural gas prices have lead to a preference for coal power plants. Such a crucial dependency also arises in numerical investment models, for instance Neuhoff et al. (2006b) find for a UK simulation that quantitative results may invert if assumptions on gas prices and investor expectations are changed. The basic conclusions here are not precise forecasts, but the fact that investments in gas power plants incur higher fuel price uncertainty and thus pose a higher financial risk to investors.

[5] See Brunner (2008) for an overview of the preceding political processes and Schafhausen (2006) for an interim ministerial report.

[6] The discrepancy is somewhat reduced because certificates used for coal during off-peak were passed through at lower rates (see above).

[7] For a more recent overview on NAP IIs see Schleich et al. (2009).

[8] '[T]he Reference Scenario is not a forecast: it is a baseline picture of how global energy markets would evolve if the underlying trends in energy demand and supply are not changed' (IEA, 2008).

Table 2
IS investment programs.
Source: Enbw.com, Eon.com, Handelsblatt, FAZ.

EVU	Time horizon	Inv. (billion Euro)[a]
EnBW	2011	7.7 (4.1)
Vattenfall	2012	6 (6[b])
RWE	2012	32 (10)
E.ON	2010	60 (12)

[a] Investments in generation capacity in brackets.
[b] Including networks.

3.3. Capital costs and financing

A third factor are capital costs and how new plants are financed. Contrary to natural gas plants, where fuel costs hold the highest share, capital costs are predominant for coal power plants (see Section 3.4), which require large investments of around 1 billion Euro and more for typical sizes (> 750 MW). Power plants are financed by a mixture of equity and loans or bonds issued at the capital market, with the relative share depending on company size, liquidity and market rating. In general there is a more favorable debt–equity ratio of up to 50:50 for the larger companies compared with 70:30 for smaller ones (A.T. Kearney, 2009). In fact, all integrated suppliers in Germany receive top ratings and thus can finance debt by issuing bonds with relatively low interest rates. Thus large investors face a comparingly favorable situation regarding new coal power plant projects. This becomes all the more important because costs for new capacity, especially for hard coal plants, have considerably increased – nearly 100% – during the last years; see for example IEA (2008) and Handelsblatt (05.09.2007). In 2007 alone six projects with a total capacity of 6.5 GW were cancelled – at least two of them due to rising investments costs (Handelsblatt, 21.01.2008). Both projects were planned by municipal utilities: SW Bremen and SW Köln. A report by Capgemini (2008) confirms that many smaller generators, mostly smaller municipal utilities, are struggling with steadily increasing capital costs in the last years. Indeed, as was shown in Section 2, the share of investors other than IS planning new coal plants is remarkably low.

The new plants are part of investment programs which have been initiated by all German IS within the last years (see Table 2). In the case of RWE and E.ON only a part of this money will be spent in Germany, but the mere numbers alone demonstrate the magnitude at stake. Even though the global financial crisis has certainly put some limits on these ambitious plans, the energy sector in comparison can still issue bonds at very favorable conditions of around 5% interest rate or even lower according to press releases by respective companies. As a matter of fact, E.ON for example has already secured three quarter of total procurement of all conventional power plants under construction worldwide (E.ON, 2008).

Taking the substantial capital required for coal, substantial cash flows have been an important prerequisite and thus a necessary condition for this development. At least three sources of increasing or additional incomes for ISs during the last years can be identified: first, as shown in the previous section inefficient capacities were closed before 2000 and only minor capacity additions followed afterwards. Second, wholesale prices had increased around 80% between 2000 and 2007 (BMWi, 2009).[9] The by then more efficient portfolios of the ISs suggest that they have increased profitability in these years. Finally, as described in Section 3.1 additional income was created from 2005 on by

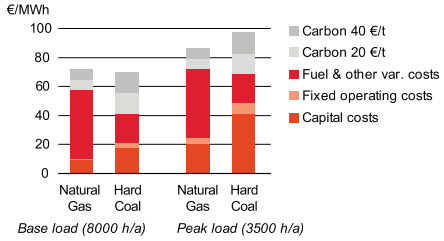

Fig. 5. Long-term new entry costs in Europe based on E.ON assumptions.
Source: Adapted from E.ON (2008).

grandfathered ETS certificates. According to data from UBA (2009a) integrated suppliers operate more than 50% (~14.5 GW) of all hard coal and nearly 100% (~21.2 GW) of all lignite plants in Germany, which makes them main profiteers of this scheme. Capgemini (2008) estimates that E.ON and RWE have earned around 5 billion Euro windfall profits from CO_2 certificates in 2007 alone. Assuming that these profits at least partly reimbursed the aforementioned investment programs, the ETS has created an exceedingly unintended outcome in this case.

3.4. Market and generation

Apart form cost aspects market factors essentially determine the profitability of a new plant. They include total demand and the detailed structure of supply (merit order), which determine the price for electricity and the capacity factor (annual full load hours) for each plant. The latter breaks down to the share of investment costs per generated unit.

The German electricity market is characterized by substantial nuclear (~21 GW) and lignite (~21 GW) capacities serving base load demand (see Fig. 5).[10] On top hard coal (~25 GW) and natural gas (~15 GW) plants supply intermediate load; peak load is served by older gas turbines and oil. In addition, around 34 GW of renewable energy capacity – mostly wind and hydro – is installed, which in 2007 has supplied 14% of the total annual demand (BMU, 2008b). Yearly fluctuations range around 40–50% of annual peak demand, leading to an operation of less costly technologies at higher number of hours during the years than more costly ones.[11] Corresponding full load hours (Table 3) thus reflect the cost structures[12] of all plants in the German market.

As has already been argued earlier, notwithstanding liberalization there is still considerable influence on the development of electricity supply from the political level in general and regulatory frameworks in particular. In 2002, the German government decided the nuclear phase out by which all respective capacity will be closed down by around 2023. Assuming this decision will be carried out as planned, around a fifth of the total capacity in the market – and half of all base load capacity – will go offline during a relatively short time period. Moreover, in 2007 an integrated energy and climate protection program (IKEP) was adopted with the following targets for 2020 relative to 2005 regarding electricity generation: (a) the share of combined heat power (CHP) shall be increased from 12% to 25%, (b) the share of renewable energies shall be increased from 13% to 25–30%, and (c) energy efficiency measures shall reduce total demand by 11%.

Assuming that both schemes will finally become reality, the electricity sector will experience a major transformation during

[9] Prices for base load fuels had also increased, but to a lesser extent (see BMWi, 2009).

[10] Capacities according to UBA (2009) and BMU (2008b).

[11] This does not apply to renewables subsidized through feed-in tariffs which in general are operated independent from demand.

[12] To a certain extent operating constraints like ramping or maintenance times also play role.

Table 3
Annual full load hours by technology.
Source: VDEW (2007).

Technology	Annual full load hours
Nuclear	7770
Lignite	6880
Hard Coal	4490
Natural Gas	3330

Table 4
Electricity demand in 2020 (relative to 2005).

Study	Demand red.
Ecofys (2008)	4.1–5.8%
BMU (2008a)	7.7–10.6%
UBA (2008a)	1.8–6.3%
EWI/EEFA (2008)[a]	−2% to 6%

[a] No explicit assessment of IKEP.

the next decade. There is considerable uncertainty though whether targets, especially demand reduction, can be reached (see Table 4). Furthermore it cannot be ruled out that a future government will suspend the nuclear phase out (Bode, 2009). This opens up certain scenarios sketched by Hilmes (2009) regarding the share of fossil (non-CHP) generation in 2020 compared with 2005, when they had a share of 48% in total generation (Table 5). Results indicate that if both policies unfold according to current plans, fossil generation will be reduced by 19%. If under a first scenario the nuclear phase out will be revoked, fossil generation will be reduced even further by 42% to only 6%. Under a second scenario, if efficiency targets cannot be reached and demand remains constant, the share of fossil generation will only be reduced by 9%. This broad span of potential developments – reductions between 9% and 42% – shows the high sensitivity of fossil generation on the political and regulatory framework.

How the various scenarios break down to a relative advantage for either coal or natural gas is not self-evident: both fossil technologies face considerable market risks in the future. Concerning the IKEP targets for renewables though, a distinct advantage will arise for natural gas from a larger penetration, especially by wind. In particular during off-peak hours high volumes of wind energy will displace conventional base load technology in the merit order and reduce the market price for electricity at the same time.[13] In fact, with increasing wind capacities, this may happen more often and over consecutive time periods. In turn this leads to a lower number of full load hours for base load technologies reducing respective profitability – a situation well anticipated in the course of new nuclear power plants in the UK (Guardian, 16.03.2009). Moreover, if the markets adept to this situations operators of base load plants may opt for a temporary shut down instead of uneconomic operation due to ramping constraints in the short run. In the long run coal and nuclear capacity may even be closed down, resulting in considerably higher prices during peak times. This situation, together with the relative flexibility in serving volatile load, would imply a distinctive advantage of natural gas over coal (see Wissen and Nicolosi, 2008).

[13] Since October 2009, the EEX allows negative bids. Since then, the electricity price has fallen below 0 € for a number of times, e.g. on 05.10.09.

Table 5
Fossil generation in 2020 compared with 2005 under various policy scenarios (modeling results).
Source: Hilmes (2009).

Nuclear phase out	Efficiency targets	Fossil generation
+	+	−19%
–	+	−42%
+	–	−9%

3.5. Cost structure comparison

Earlier in the article it was claimed that natural gas can be seen as the only viable alternative to coal for new investments in Germany. The factors discussed so far allow a comprehensive comparison of the cost structures of both technologies at this point, which will clarify the economic validity of this assumption. In fact, the German energy regulator for example states that there exists no direct competition between power plant technologies of different load levels (BnetzA, 2006).

Fig. 5 shows levelized unit costs for hard coal and natural gas based on E.ON assumptions.[14] Total costs consist of two parts: fixed capital and other operation costs, which decrease with increasing annual full load hours (see above), and variable costs independent of the capacity factor, predominantly fuel and carbon costs. Without taking carbon costs into account the traditional segmentation of technologies along load levels can be observed. Hard coal, where capital costs are high and fuel costs are low, becomes increasingly attractive if extensively utilized, whereas for natural gas the opposite holds. It must be added that E.ON's choice of capacity factors in Fig. 5 does not reflect the current situation (see Table 3). Nevertheless, the extreme cases depicted are useful to explore limits. Moreover, state of the art hard coal technology allows base load operation (BKartA, 2007), which justifies 8000 full load hours per year for this technology.

Taking the full spectrum of costs including carbon, as will be the case from 2013 on (see Section 3.1), the cost differentials between hard coal and natural gas will shrink significantly. The obvious reason is hard coal's higher carbon intensity, which is roughly twice as high as that of natural gas (see Konstantin, 2009). With relatively marginal differences in costs, the risks associated with each factor may play a decisive role. In particular future prices for carbon and fuel will be essential. Carbon prices have already been accounted for with some sensitivity (20EUR/t,40EUR/t) – current forecasts suggest these magnitudes are reasonable for the mid future, but in the long run prices may be higher (see Section 3.1). Concerning fuel prices, scenarios forecast an increase for natural gas until 2030 up to around 100%, whereas upper limits for hard coal are only in the order of 50% (see Section 3.2). So the existing disparity in absolute fuel costs as shown in Fig. 6 may likely intensify in the years ahead. In summary, concerning technology choice the costs of fuel and carbon and their respective risks rather exclusively support different options: with a focus on fuel hard coal is more favorable, with a focus on carbon it is natural gas.

3.6. Carbon capture and storage

In the light of the previous findings, carbon capture and storage (CCS) is a promising technology especially for operators of coal power plants. Regulatory and legal frameworks are currently

[14] For scientific assumptions see for example Konstantin (2009).

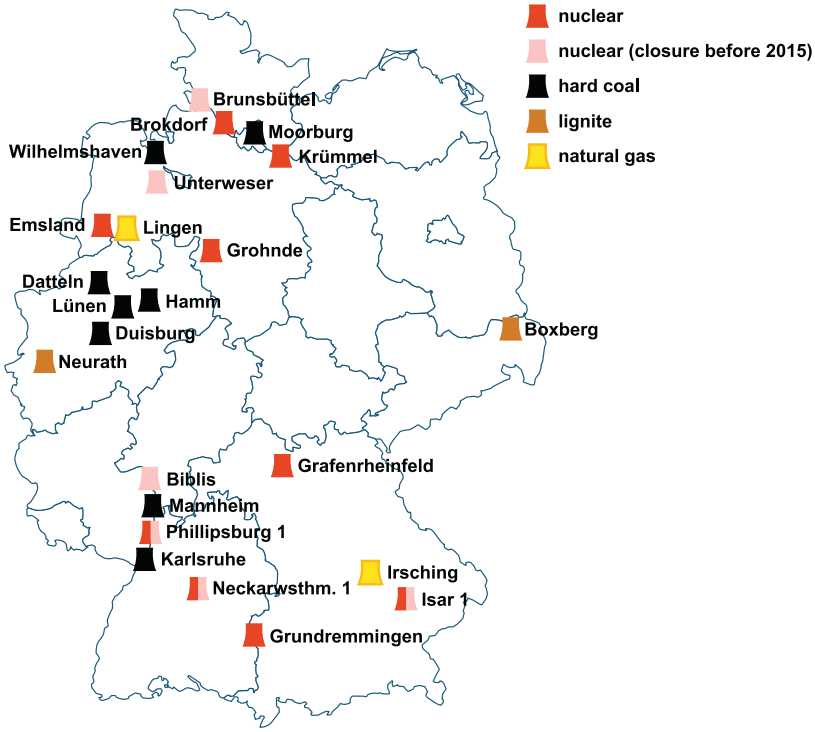

Fig. 6. Locations of fossil (in construction) and nuclear power plants.
Source: Adapted from UBA (2009c), BUND (2009).

in preparation on EU and national level, and CCS appears to gain momentum, even though there are still many unresolved problems; see e.g. MIT (2007). In Germany all IS are engaged in pilot projects except EnBW, which only cooperates in R&D projects with the University of Stuttgart and VGB PowerTech. Vattenfall already operates a 30 MW lignite/hard coal pilot plant in Schwarze Pumpe. The capacity is envisaged to be extended to 375 MW incurring total investments of around 1 billion Euro (Reuters.com, 06.03.2009). RWE has announced a 450 MW lignite plant in Hürth to be commissioned in 2014 with a total budget of around 2 billion Euro. Moreover, pilot facilities for capturing CO_2 are planned by the UK division RWE npower. According to press releases E.ON has announced three smaller pilot projects for post combustion in Germany, all of them in cooperation with other firms. The biggest projects though are planned in Kingsnorth and Killinghome (UK); an investment plan has already been submitted to UK government as part of its CCS program for pilot projects with a total budget of 1.5 billion £ (Carboncommentary.com, 14.01.08). All companies have applied for partial public funding of their projects.

Having CCS available represents a valuable option once certificate prices rise to higher levels. Assuming it will prove feasible, associated abatement costs can be interpreted as a 'ceiling' on the certificate price, i.e. operators either buy certificates or equip plants with CCS depending on the respective costs. Costs estimates are roughly in the same order of magnitude: IEA and McKinsey predict abatement costs of 35–60$ and 30–45€/ton if CCS reaches maturity around 2030 (Economist, 05.03.2009). As technological costs in general follow a downward slope while the price for certificates should follow an upward slope (see Section 3.1), CCS will probably be the economic choice in the long run. DB Research (2008) goes even further by stating that they think the ETS policy objective is actually to make CCS power plants the new entrant of choice by 2020. Hence it can be argued that CCS can preserve current technology cost rankings as discussed above, where otherwise a constantly rising certificate price would gradually make natural gas profitable, even in base load levels. There are still high uncertainties if CCS will ever become a feasible technology and at what costs, but if it does it will definitely yield higher benefits for coal than for natural gas.

3.7. Thermal efficiency

A major disadvantage of CCS is a loss in plant efficiency of about 9–10 percentage points due to additional energy required for capturing and compressing CO_2. To a certain part this can be counteracted by the increase in efficiency achieved by state-of-the-art power plant technology. This comes along with a need for modernization: even though current average coal plant efficiency of 38% still ranks high on global level (Ecofys, 2007), relatively large improvements appear possible. Referring to the thresholds defined by a 'Malus rule' in NAP I it can be assumed that at present the lower limits are 32% for lignite plants and 36% for hard coal plants. Indeed, as Hoffmann (2007) reports, energy companies have retrofitted affected plants during the first ETS period to meet these limits. So efficiency gains of 10–15% in particular for older plants seem realistic. Moreover, either with CCS or without, reducing fuel intensity in power generation leads to a more economic cost structure and thus can be a favorable investment option. Table 6 shows the potentials of future technologies as reported by BMWi (2008).

As can be seen expected efficiency gains within the next decade amount to at least 5–6% for coal and around 4% for natural gas. This is also confirmed by Brunekreeft and Bauknecht (2006), who highlight that strong technological advances are expected for

Table 6
Technology efficiencies.
Source: BMWi (2008).

Technology	State-of-the-art	Est. efficiency 2020
Lignite	43–44%/47%[a]	> 50%
Hard Coal	45–46%/50%[b]	> 50%
Natural Gas	59%	63%

[a] RWE WTA Technology.
[b] E.ON Wilhelmshaven 50+.

coal. Currently there are two projects at the technological frontier, both supported by public R&D programs: a supercritical hard coal plant (> 50%) by E.ON in Scholven (COMTES700) and Wilhelmshaven (planned for 2015), and a new technology for pre-drying lignite (WTA) by RWE which increases efficiency of lignite plants up to 47%. This underlines that electricity companies are actively engaged in further exploiting the potentials, especially for coal. Even though both technologies are relatively mature, potential advances and R&D activities pushing them forward suggest that coal will improve its position compared with natural gas in the future. A global rising demand for new coal power plants, especially in China and India, will possibly accelerate this trend.

3.8. Replacing and siting

In comparison to decision factors the question of what actually drives investments has been hardly dealt with so far. Especially if new capacities are added or planned extensively, it can be assumed that the drivers are tangible in the sense that investments are made by a substantial part of the sector and not only a single company. In this regard Platts (2008) subsumes that '[t]raditionally, the construction of large power projects in fully-developed economies was driven by requirements to replace older plants and meet load, thus imparting a cyclical nature to the deployment of new plant as large-capacity units were added in step-wise fashion'. Even though this does not hold to full extent in the now liberalized markets any more,[15] replacement still represents an important factor if plants must ultimately be closed for technical or political reasons. In such cases where old facilities cannot be upgraded or retrofitted, a new plant must be built which in principle implies a new choice of technology. However, from a market perspective one could argue that the new plant should 'fill the gap' created by the closure of the old one. As long as demand profiles and supply structure do not change significantly, the supply-demand equilibrium is probably best maintained by choosing a similar cost structure and load level.

Taking the age structure of installed capacity in Germany as described in Section 2.1, it becomes clear that there is a considerable necessity for replacement over the next years. In 2008 around 35 GW of conventional capacity was 30 years or older; thus many plants have outlived average lifetimes of 25–40 years. This situation has been foreseeable for many years and created a permanent debate whether the liberalized market will create appropriate incentives for companies to make sufficient investments; see for example Ziesing and Matthes (2003) for an early, and DENA (2008) and Matthes and Ziesing (2008) for recent contributions. In any case an ample modernization of the German electricity sector is pending. The most pressing needs thereby certainly arise due to the nuclear phase out in Germany (see Section 3.4). Of the 17 nuclear generating units currently online, seven with a total capacity of around 7.4 GW are estimated to go offline by 2012 (Table 7).[16] Moreover, for the same period energy companies have announced to close down around 2 GW of lignite, 1.5 GW of coal and 0.1 GW of natural gas capacity (BnetzA, 2008).

Hilmes and Kuhnhenne (2006) give a precise account of how replacement requirements break down to the single companies and what their options are. By doing so they presume that nuclear power plants will be replaced with other base load technologies as argued above; primarily hard coal, and lignite where available. In their conclusion they point out the relevant limiting role of location factors thereby. This is analyzed in more detail in a study by Reich and Benesch (2007) who discuss location factors for hard coal power plants and apply them to the German situation. They include fuel supply and transport, cooling, network connection and site synergies like existing infrastructure and additional supplementary installations (e.g. filters). The most important factor, transport costs, virtually restricts new hard coal plants to sites at the coast or the main rivers connected to the North Sea (Rhein, Main, Elbe). Total cost differential of all factors may add up to 10.3€/MWh in the worst case implying a considerable competitive disadvantage.[17] As another factor, proximity to centers of demand may also be of advantage, at least from a network capacity point of view. Even though there is no spot pricing for network transmission in Germany, there is a risk that more distant plants must be temporarily shut down because of network stability reasons. This applies in particular if plants are located in areas with high shares of intermittent renewable capacity, which due to the national Renewable Energy Act (EEG) have prioritized grid access.

Choosing an existing site for new built is thus more preferable than developing a new site for at least two reasons. First, locations were chosen in the past because they were of economic advantage, and respective criteria probably have not changed since. Second, drawing on existing sites may facilitate planning and construction. One consequence of this situation is a certain restriction on technology choice. Requirements on cooling and network connection may overlap, but fuel supply becomes a very important factor here. In general one fuel cannot be economically substituted for another one. This holds in particular for lignite, which virtually leaves no room for choosing locations other than in close proximity to the mining districts. In fact, the fossil power plants currently under construction confirm this picture: all twelve larger (> 100 MW) projects are built on already existing sites, and in only two cases, which will be discussed in more detail below, the replacement included a technology switch.

Drawing on the previous finding the replacement assumption can now be analyzed on the scale of single plants. Taking the constraints of existing transmission infrastructure for large centralized capacity, the 'replacing plant' should be located in proximity to centers of demand previously served by the old plant. A map of nuclear and planned fossil power plants (Fig. 6) shows that matching is possible to a certain extent. Three regions can be identified where the nuclear phase out will produce a gap in capacity during the next years (see Table 7): (a) in the south (Isar), (b) in the southwest (Biblis, Neckarwestheim, Philippsburg), and (c) in the north (Unterweser and Brunsbüttel).[18] E.ON builds a large natural gas plants at Irsching in the south, and a coal power plant at Wilhelmshaven in the north, where an additional

[15] See for example Murphy and Smeers (2005) and further remarks in Platts (2008).

[16] Following the September 2009 elections the current coalition agreement envisages an extension of lifetimes. However, current coal plants as potential replacements were initiated already years ago under the 'old regulation'.

[17] This equals around 10–15% of the long-term new entry costs estimated by E.ON (see Fig. 5).

[18] For further details on operator and capacity see Table 7.

Table 7
Nuclear power plants with estimated closure before 2015.
Sources: UBA (2008a), BFS (2009).

Plant/unit	Capacity (MW)	Location	Est. closure[a]	Operator
Biblis A	1225	HE (Rhein)	2009	RWE
Biblis B	1300	HE (Rhein)	2010	RWE
Neckarwestheim 1	840	BW (Neckar)	2010	EnBW
Brunsbüttel	806	SH (Elbe/North Sea)	2011	E.ON (33%)/Vattenfall (66%)
Isar 1	912	BY (Isar)	2011	E.ON
Philippsburg 1	926	BW (Rhein)	2012	EnBW
Unterweser	1410	NI (Weser/North Sea)	2012	E.ON

[a] Calculated based on remaining quota and annual output of the last operative year.

one by EDF GUEZ is under construction. Another coal plant is projected at Hamburg Moorburg by Vattenfall. Comparing ownerships of new and old plants supports the aforementioned hypothesis. Moreover, in the southwest EnBW builds a new coal plant at Karlsruhe, and RWE would have also done so at nearby Ensdorf, had the project not been cancelled. Apparently hard coal nearly exclusively replaces the nuclear plants that will be phased out in the near future. The only exception can be found in the southwest (Isar) where coal is not a cost-efficient alternative.[19] So only in this case, limited by location factors 'inherited' from nuclear technology, natural gas becomes a fall back alternative. Summing up, there is evidence that investors in the current German power market predominantly replace one technology with another that has similar economic and technological properties. This has limitations only where location factors would render the new plant uneconomic.

3.9. Public acceptance

Also related to siting is the issue of public acceptance, which in particular applies to coal plants. Apart from a general loss of image and reputation for investors, administrative barriers can be enforced through revisions of land utilization plans and water regulations for rivers that limit heat absorption and consumption. Indeed, these steps in the authorization process have proven effective means for opposing local politicians or authorities in the past. Relevant examples, having received considerable public attention, are the coal plants in Moorburg (Hamburg), Klingenberg (Berlin), and Ensdorf. All projects faced or still do face public opposition – and all took a different end. Concerning Moorburg, the investor Vattenfall has adhered to the project against all protests by local civic and political interest groups. Vattenfall's second project Klingenberg, however, was changed to a smaller natural gas plant and additional biomass capacity. These decisions, made by one and the same investor, seem ambiguous but probably make more sense from a perspective of replacement: Moorburg will probably replace Vattenfall's shares in the nuclear plants Brunsbüttel, Krümmel, and Brockdorf, while the old Klingenberg plant generates CHP and serves district heating which makes natural gas a tolerable alternative. It remains an open issue which factors finally guided Vattenfall's decisions in either case, but attributing Klingenberg to just giving in to public protest seems too simple. On the other side, the third project in Ensdorf planned by RWE was turned down by the local government after public protests.[20] Furthermore, BUND (2009) lists seven projects with a total capacity of 8.8 GW that were turned down, but only gives a vague assessment of the reasons. Two of them were classified as cancelled due to public resistance, but the reasons may actually be manifold in reality. In summary public resistance is often quoted as an essential threat to new projects, but a clear identification of its relevance to investors awaits further research. In the meantime the plants currently under construction provide evidence that the effectiveness of public protest is not comprehensive.

3.10. Political support for coal

The examples of allocation of emission certificates, political frameworks and R&D activities have shown that political influence shapes developments in the power sector significantly. This applies to both direct economic support like R&D subsidies or tax breaks and indirect political support like administrative assistance and a political representation of interests, for example on the EU level. Energy policy in Germany, though now partly in responsibility of the ministry of environment (BMU), still falls in the domain of the ministry of economics (BMWi). The BMWi hast recently established a working group (*PEPP, Projektgruppe Energiepolitisches Programm*) to develop an energy roadmap on its behalf. It came to the conclusion that conventional fuels will still be an important pillar of energy supply in the next decades, while at the same time fossil fuels must be used more efficiently and be 'decarbonized' (PEPP, 2009). The minister in charge at the time emphasized that electricity supply based on coal, including respective new power plants, is absolutely necessary (BMWi, 25.9.2008). But it is rather the BMU that traditionally acts as proponent of pro-environmental action, e.g. in shaping renewable electricity policy (Lauber and Metz 2006). The BMU also published an energy policy roadmap in early 2009 (BMU, 2009b) which targets 40% of all electricity in 2020 shall be generated by highly efficient coal power plants. It explicitly refers to this measure as a necessary condition for the prioritized nuclear phase out.

Still, the broad support along the administrative spectrum reflects only the current political constellation and considerable uncertainty remains. On one side, the nuclear phase out is continuously challenged by the liberal and the conservative party (Bode, 2009), and lifetime extensions for current plants will very likely become reality. On the other side, the Green party fiercely opposes new coal power plants, even though the new plant in Moorburg has shown that in coalitions concessions must be made. In fact, of all factors influencing technology choice neither seems so much out of the investor's control as prolonged political support. Correspondingly, the appeal for stable investment frameworks is echoed all around. If however – as present trends seem to indicate – coal will become established as a cornerstone in German energy policy, then political support will very likely sustain into the future.

[19] The power plant at Lingen obviously falls short of this explanation. However, the site has existed since the 1970s and was used for natural gas ever since.

[20] According to UBA (2009b) this has been the only case so far where local resistance actually caused a project to be turned down.

4. Conclusions

After exploring drivers and decision factors, a plausible narrative of the dash for coal in Germany can now be devised. Drawing on economic, technological, and socio-political influences on technology choice, this development presents itself as a plausible outcome when seen from the perspective of the IS group of investors. Even though the lack of a theoretical foundation and the exploratory character limit evidence somewhat, this analysis may actually present the by now most comprehensive account of this issue. In finally returning to the question why there is a dash for coal, five fundamental explanations can be concluded.

First, the need for replacement has been the key driver for new coal plants, especially the large amount of nuclear capacity that will be decommissioned during the next years. The excess of age of many coal plants in the sector also plays a role, but the nuclear phase out is both more extensive and pressing due to the regulated end of lifetimes. Lignite, currently the other technology supplying base load and thus a preferred alternative, is limited to locations in general too far off from nuclear sites. Thus, hard coal with similar costs structure and state-of-the-art technology allowing high capacity usage steps in to fill the gap. Only in the few cases where location factors render this technology unprofitable, natural gas becomes an alternative.

Second, relevant investors were able to set up large programs and secure their investments in new coal plants. A main barrier for building coal power plants is the high cost of capital which limits this technology's availability to financially strong investors. This situation has intensified during the last years when costs went up around 50–100% from former levels. Indeed, many smaller utilities which announced plans struggled and finally gave up their projects. By contrast large investors, primarily the four German IS, were able to exploit their economic scale and high financial ranking to gain favorable, or at least acceptable, conditions for investing. In addition, an optimized portfolio of plants and rising electricity prices in the aftermath of liberalization helped to raise equity. Further revenues in the order of billions of Euros were obtained through windfall profits from grandfathered emission certificates. Much in disregard of its intention, the EU ETS has thus eventually fostered the dash for coal.

Third, in the long run operation costs for coal are lower and less risky than for natural gas, combined with a higher technological potential of coal. The future profitability of hard coal, in particular in competition with natural gas, highly depends on long-term fuel and carbon prices. As the spectrum of scenarios and a number of fundamental facts suggest, coal prices will be considerably more stable and thus less of a risk than natural gas. On top, the greater technological potential for further efficiency improvements for coal increases this advantage. Regarding carbon, upcoming full auctioning in the EU ETS and stricter reduction targets will increase variable costs of coal compared with natural gas. Under this situation CCS becomes a promising option as it could put an upper bound on carbon prices. If long-term costs of CCS will converge to around 40€ as widely expected, than this will cap abatement costs at exactly this level. As E.ON's assumptions in Fig. 5 indicate, a similar level of CO_2 prices (40 €/t) constitutes the turning point above which conventional coal becomes the more cost intensive technology. Thus if all assumptions hold, CCS may sustain the original cost ranking in the long run. Some market analysts even suspect that it is the sole objective of the ETS to bring CCS on the way, and indeed many policy makers have made CCS an inherent part of their strategy. This is put succinctly by the Head of Research of a German IS, who states that they believe that coal plays an important role for electricity supply after 2020, and in view of climate protection agreements it can only do so by means of CCS (personal communication). The risks and still unresolved difficulties to implement this technology are eagerly neglected in these strategies, but it obviously has become sufficiently mainstream among politicians, analysts, scientists and investors alike to substitute potential by availability.

Fourth, investors seem to ignore or underestimate the impacts of the envisaged large-scale integration of renewables into the energy mix. As is commonly agreed, the steady increase of renewable generation will significantly change the structure of power supply in the future. In 2007 the IKEP targets amounted to 25–30% until 2020, and they have become even more ambitious only two years later with EU directive 2009/28/EC heading for 35% by 2020 and perhaps 50% by 2030. Extensive deployment will both crowd out conventional fossil generation and interfere with traditional supply patterns. In consequence, the historic differentiation between base load and peak load will gradually dissolve. In fact, impacts of high wind generation on base load generation if demand is low are already visible today. It remains an open question if ISs expect these targets to be reached, and if so, as early as planned. In this regard, the amortization period for new plants may play a role which in general is considerably shorter – around 20 years – than actual technical lifetime. ISs possibly see the upcoming transitional period as sufficiently long in order to pay off new plants. However, in contrast to what was expected during planning, a certain chance exists that the new coal plants may eventually become unprofitable.

And fifth, public protest proved little effective to hamper new coal plants, which otherwise had broad political support. As a 'dirty' technology coal raises many concerns about the environment and global warming especially in the German society. Every new project is confronted with more or less protests by citizens' initiatives, environmental interest groups and local authorities. Even though there are claims that these oppositions have brought a number of plants to a stop, there is evidence in only one case (Ensdorf). In a second case, a change in technology was obtained, but in summary investors' plans were not hampered in a substantial way. On the political stage, the majority of parties supports coal under the provision of efficient usage, seemingly on purpose avoiding a clearer definition. For whatever reasons, there has been general political support behind coal technology without which investors would have definitely faced a more serious obstacle than plant-wise local protests. As a matter of fact, and notwithstanding the liberalization of the electricity sector, the dash of coal has also emerged out of political will.

From the perspective of climate policy the question arises if this development is a serious threat to reach future reduction targets. In particular, very ambitious reductions require a transition to a low carbon energy system, which in turn requires that power companies make significant changes in their investment flows from traditional practices. Adhering to fossil technologies may further intensify the carbon lock-in of the sector, assuming that new plants will operate for 40 years or more. But the same rigidity of the long lasting infrastructure of energy supply may also require an extended interim period. It is a chief task of climate policy to address this problem in a socially beneficial way, and it is a chief task for science to reveal the underlying processes and point out potential pathways for doing so.

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Chapter 3

How emission certificate allocations distort fossil investments: The German example*

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How emission certificate allocations distort fossil investments: The German example ☆

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ABSTRACT

Despite political activities to foster a low-carbon energy transition, Germany currently sees a considerable number of new coal power plants being added to its power mix. There are several possible drivers for this "dash for coal", but it is widely accepted that windfall profits gained through free allocation of ETS certificates play an important role. Yet the quantification of allocation-related investment distortions has been limited to back-of-the envelope calculations and stylized models so far. We close this gap with a numerical model integrating both Germany's particular allocation rules and its specific power generation structure. We find that technology specific new entrant provisions have substantially increased incentives to invest in hard coal plants red to natural gas at the time of the ETS onset. More precisely, disproportionate windfall profits compared more than half the total capital costs of a hard coal plant. Moreover, shorter periods of free allocations would not have turned investors' favours towards the cleaner natural gas technology because of pre-existing economic advantages for coal. In contrast, full auctioning of permits or a single best available technology benchmark would have made natural gas the predominant technology of choice.

1. Introduction

During the last years considerable investments in new coal capacities were brought on the way in the German electricity sector. In total ten plants are currently under construction, which after completion will add around 11.3 GW to the market (BUND, 2010). Besides, there are plans for more than 12 additional plants. Taking together all projects – the majority of them hard coal – possible expansions amount to approximately 32% of German peak electricity demand in 2008 (Bundesnetzagentur, 2009). Realizing that for several years after liberalization in 1998 natural gas was the predominant option (Brunekreeft and Bauknecht, 2006), this development constitutes a dramatic shift in technology choice.

In a hierarchical analysis, Pahle (2010) explores drivers and decision factors that may have given rise to this "dash for coal". Several factors are identified which suggest themselves as necessary conditions or drivers. Among them, the German national allocation plans (NAPs) of the EU Greenhouse Gas Emission Trading System (ETS) have presumably played an important role by providing free certificates for new entrants according to fuel specific benchmarks—see overviews by DEHSt (2005) for NAP I and Schleich et al. (2009) for NAP II. For conventional fossil fuels this implies that the "dirtier" technology coal received a higher absolute allocation than its "cleaner" competitor natural gas. Electricity generators were able to generate windfall profits by passing through opportunity costs—see for example Sijm et al. (2006) and Zachmann and von Hirschhausen (2008). Accordingly, investment incentives were biased towards the dirty technology. This distortion has been widely acknowledged in the literature, for example by Ellerman (2008) and Neuhoff et al. (2006a, b).[1] In this article, we use a numerical model to quantify the effects of German allocation rules on thermal investment decisions in Germany around the year 2005. We find that the windfall profits created by NAP I have further increased an already existing preference for coal investments compared to natural gas. In contrast, counterfactual allocation rules like full auctioning of permits or a single best available technology benchmark would have substantially increased natural gas investment incentives.

Research to assess and quantify the created economic incentives has been surprisingly sparse so far. In an interview-based

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[1] See also Fan et al. (2010) who point out that risk aversion may further enhance this bias.

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study of investment decisions in the German power sector, Hoffmann (2007) draws an ambiguous picture of the EU ETS influences. On the one hand, investments still depend on fundamentals, in particular on fuel prices and respective scenarios. On the other hand, there is evidence that "current projects are only profitable due to the development of the EU ETS" and "did not work out in 2003 due to the [...] non-existence of the EU ETS". Additional support comes from numerical models, albeit applied to other countries (cp. Burtraw and Palmer, 2008). For the UK Neuhoff et al. (2006a) confirm additional coal power plant investments, but also acknowledge that results may invert if assumptions on gas prices and investor expectations are changed. Laurikka and Koljonen (2006) compare investment opportunities for gas and coal plants in Finland under uncertainty, using stochastic electricity and certificate prices. They conclude that the allowance market can have significant impact on the expected profitability of gas plants, whereas the value of new coal plant investment remains mainly unaffected. Because they do not take account passed-through opportunity costs and windfalls profits, their results fall short of assessing the above mentioned investment distortion. One of the few contributions so far explicitly integrating windfall profits is Taschini and Urech (2009), who analyze how expected windfall profits will affect operation and profitability of different technologies. They find that when opportunity costs are internalized, there is a shift towards coal-fired generation somewhat contrary to intuition. However, they use a rather stylized model and a fixed allocation regime not adapted to any particular market. In summary, the distortionary effect of a fuel-specific new entrant reserve and windfall profits on investment and technology has not been quantified for Germany so far (cp. Hentrich et al., 2009). This article aims to fill this literature gap, where the above described "dash for coal" suggests that respective distortions in fact played an important role.

Our analysis is based on a discounted cash flow (DCF) model similar to Laurikka and Koljonen (2006) who use a stochastic price distribution. Investment options are evaluated by their overall performance in the market according to the net present value (NPV) criteria. Related literature applies real options methods (see for example Reedman, 2006; Blyth et al., 2007; Reinelt and Keith, 2007; Szolgayova et al., 2008; Patino-Echeverri et al., 2009), which considers the value from obtaining information on future uncertainty. These models, however, rely on an exogenous stochastic price process. In contrast, we deterministically compute both the price of electricity and the quantity a plant can sell endogenously, based on a detailed representation of demand and supply (merit order). A comparable method has been used for example by Weigt and Hirschhausen (2008) for an analysis of short term market power in the German wholesale market. Other applications include the impact of carbon pricing on cycling costs (Denny and O'Malley, 2009). In this case, combining DCF with a merit order representation poses the distinctive advantage to have a bottom-up representation of fuel costs and allocation schemes. Due to this prices and cash flows can be determined by means of fundamentals, which is an essential requirement in face of our research question.

We retrospectively look at the year 2005 when the ETS became effective. From this point of reference, we analyze the bias created by free allocation of certificates for either hard coal or natural gas towards the choice of a pending capacity investment. Doing so implicitly assumes that both technologies are the only viable alternatives.[2] Effectively, this breaks down to a comparison of relative rather than absolute profitability, which proves to have important influence on methodology and calibration. An important point in this regard is that we do not intend to capture actual investment decisions, but rather quantify the relative impact on profitability of different technologies.

We also investigate the impact of the length of the period with free allocation on investment decisions. In particular, we are interested in how its length will affect the investment value through the cash flow over the plant's lifetime. A crucial role is played by the discount factor, which determines how important the investor considers future revenues. For example, a high discount factor enforces the effect of an initial free allocation period because the investor puts less weight on future gains, and vice versa. Bergerson and Lave (2007) compare investment values under different schedules for carbon taxation and discount rates (private, social). In accordance to their findings our results also suggest that the interplay of discounting and transitional policy periods may be of high importance for power sector investments. Nonetheless, we find that shorter free allocation periods would not have been sufficient to reverse the economic preference for coal under initial allocation rules (NAP I).

Although our analysis has a retrospective focus, we touch a very topical issue here as several currently unresolved questions could benefit from hindsight. For example, the discussion about initial allocation and efficiency of a trading scheme currently seems to gain new momentum (Hahn and Stavins, 2010). However, sound scientific evidence of this issue is yet far from comprehensive (cp. Convery, 2009). Especially inframarginal rents due to free allocation as well as the particular rationality of certificate costs pass-through are still only roughly quantified and vaguely understood (Keppler and Cruciani, 2010). Our findings may thus sharpen understanding and provide helpful information for the design of future allocation schemes.

The remainder is structured as follows. Section 2 introduces the methodology and the model. Section 3 includes all relevant data and parameters. Section 4 discusses the results. The last section summarizes and concludes.

2. Methodology and model

2.1. Investment rationale

We model the investment decision of a generator building a new centralized fossil power plant of typical size (1000 MW). The technologies k under comparison are hard coal and natural gas. The preferred technology is determined by the relative difference of the net present values (NPV) over the financial lifetime T_{FL} between either option.

The primary cash flow of the plant is determined by two factors: the overall number of hours the plant can sell to the market (full load hours) and the price of electricity $p_{el}(t(j,t))$ in respective periods.[3] The electricity price is derived endogenously from the merit order based on generators' supply bids and (exogenous) demand in the market.[4] Demand is represented by different periods j subsuming hourly fluctuations over the year. It is characterized by demanded quantity in $d(j)$ and duration $hr(j)$. We assume marginal cost pricing, thus in each of these periods the electricity price equals the generating costs of the marginal plant. In consequence the new plant sells to the market if demand exceeds its specific position in the merit order, i.e. when it is submarginal as specified in the

[2] For further argumentation that this indeed was the case in Germany, see Pahle (2010).

[3] We assume that the plant just sells electricity to the German wholesale market. We neglect possible additional revenues from the balancing market, as this market is beyond the scope of the article.

[4] We only consider the wholesale market that is completely separated from the balancing market in Germany.

Table 2.1
Sets, indices, parameters and variables.

	Description	Unit
Indices		
t	Year index relative to base year (2005)	
k	Technology index: hard coal (HC), natural gas (NG)	
j	Demand period index	
T_{FL}	Time span in years over which the NPV is evaluated	
$T_{FA} \subseteq T_{FL}$	Subset of T_{FL} in which certificates are allocated for free	
$T_{AUC} \subseteq T_{FL}$	Subset of T_{FL} in which certificates are auctioned	
Exogenous parameters		
$cap(k)$	Capacity of the model plant	MW
$d(j)$	Demand	GW
$hr(j)$	Number of hours per year in which demand equals $d(j)$	hr
$c_{cap}(k)$	Capital costs	€/kW
$c_{OM}(k)$	O&M costs	€/(MW × a)
$p_{fuel}(k,t)$	Fuel price	€/MWh$_{th}$
$p_{CO_2}(t)$	Price of CO_2 certificates	€/t
$c_{el}(k,t)$	Variable costs of electricity	€/MWh$_{el}$
$alloc(k)$	Annual free allocation of certificates	t/MW
$\eta(k)$	Thermal plant efficiency	
$cef(k)$	CO_2 emission factor	t/MWh$_{th}$
δ	Discount rate	
$ptr(k,t)$	Technology-specific pass-through rate of CO_2 costs	
Endogenous variables		
$p_{el}(j,t)$	Electricity price set by the bid of the marginal plant in each demand period	€/MWh
$bid(k,t)$	Supply bid to market	€/MWh
$GEN(k,t) \subseteq j$	Subset of all demand periods where new capacity can sell to market	

generation subset of demand $GEN(k,t)$. Thus the generator acts as a price-taker implying that the new capacity is small compared to the overall market and not part of a larger portfolio which could offer strategic options.[5] Other operating constraints like ramping times are excluded for sake of simplicity.

The cost of generating electricity consists of two parts. First, variable costs depending on the fuel price $p_{fuel}(k,t)$ and the price of CO_2 certificates $p_{CO_2}(t)$; and second, capital costs per unit $c_{cap}(k)$ for the initial investment and fixed O&M costs $c_{OM}(k)$ per year. Yet only the variable costs do affect price formation. To compute fuel and emissions costs, the thermal efficiency $\eta(k)$ of the technologies is required. Moreover, the number of CO_2 certificates required for compliance is determined by the carbon emission factor $cef(k)$, which specifies emissions per unit of fuel used. We allow for asymmetric cost pass-through by differentiating between actual costs of generation–which include full carbon costs – and generators' supply bids $bid(k,t)$ to the wholesale market. A generator's bid only includes a fraction of the full CO_2 costs given by the pass-through rate $ptr(k,t)$. We provide further explanation of asymmetric cost pass-through in Section 2.2.

Another essential feature of the model is the inclusion of two succeeding periods of emission trading: at first, for a certain time span T_{FA}, permits are allocated for free according to a certain scheme which quantifies the allocation $alloc(k)$ per MW installed capacity and year (see Section 3)[6]. This endowment – multiplied by plant size and CO_2 price–constitutes an additional positive cash flow. During the second period, extending over the remaining years T_{AUC}, permits are auctioned and must fully be bought from the permit market, which implies a purely negative secondary cash flow and thus no windfall profits.

The NPV is evaluated over the financial lifetime of the potential plant. It comprises the initial capital expenditure as project costs and the sum over the future discounted profits as cash flow. The discount rate δ used is understood as a specific mark-up inherent to the project that resembles the associated risks and thus the investor's myopia. The overall model reads (see Table 2.1 for a description of sets, indices, parameters and variables):

$$\begin{aligned} NPV(k) = & -cap(k)c_{cap}(k) - \sum_{t \in T_{FL}} cap(k)c_{OM}(k)(1+\delta)^{-t} \\ & + \sum_{t \in T_{FA}} \left\{ \sum_{j \in GEN(k,t)} [p_{el}(j,t) - c_{el}(k,t)]cap(k)hr(j) \right. \\ & \left. + alloc(k)\,cap(k)\,p_{CO_2}(t) \right\} (1+\delta)^{-t} \\ & + \sum_{t \in T_{AUC}} \left\{ \sum_{j \in GEN(k,t)} [p_{el}(j,t) - c_{el}(k,t)]cap(k)\,hr(j) \right\} (1+\delta)^{-t} \end{aligned}$$

where

$$c_{el}(k,t) = [p_{fuel}(k,t) + p_{CO_2}(t)cef(k)]/\eta(k)$$
$$bid(k,t) = [p_{fuel}(k,t) + ptr(k,t)p_{CO_2}(t)cef(k)]/\eta(k)$$
$$GEN(k,t) = \{j \,|\, p_{el}(j,t) > bid(k,t)\}$$

2.2. Price formation, generation, and CO_2 cost pass-through

An important feature of our analysis is the endogenous determination of electricity prices and full load hours to compute the NPV of a new plant. In order to do so, we make use of a detailed structural representation of the underlying market to create the merit order, i.e. the aggregated supply curve of all power plants. Fig. 2.1 shows the stylized German merit order and demand distribution in the reference year for given fuel prices (see Section 3 for data and assumptions). It comprises all available generation capacities according to their short-run marginal costs, from renewables on the left to peaker plants on the right side.

Over the course of a year demand varies to a considerable extent; overlaid lines in Fig. 2.1 represent annual fluctuations. Due to the marginal cost pricing assumption a plant sells to the market during

[5] This corresponds best to an independent power producer operating a single merchant plant.

[6] We assume free allocation without ex-post correction. Generators receive a certain amount of certificates which is not adjusted later on according to actual electricity generation.

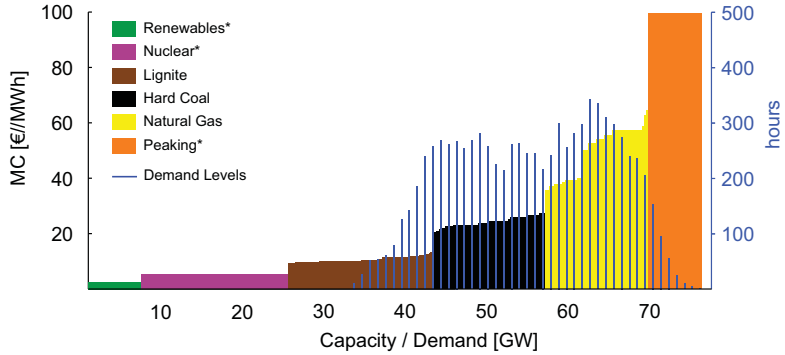

Fig. 2.1. Stylized German merit order and demand distribution in reference year; w/o carbon costs; *stylized representation (UBA, 2009; ENTSO-E 2010, own calculations).

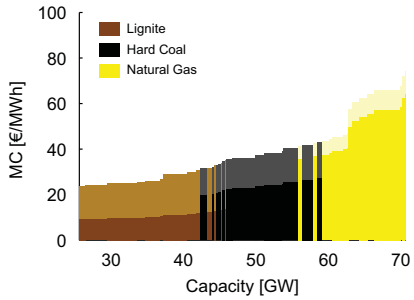

Fig. 2.2. German fossil merit order (2005) with carbon costs of 15 €/t (lighter shades).

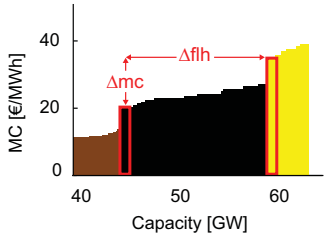

Fig. 2.3. New plants w/o CO_2 costs.

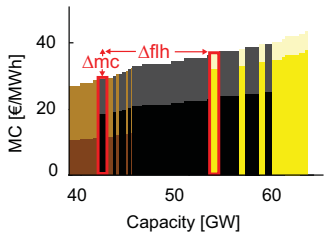

Fig. 2.4. New plants with CO_2 costs.

all periods in which demand exceeds its specific position in the merit order. In turn, given the frequencies of occurrence for different demand levels, this determines the number of full load hours.

Both electricity prices and plant-specific full load hours are highly dependent on the merit order. One of its essential characteristics in this regard is the stepped shape due to the different technologies with distinct cost structures. All capacities of equal technology are represented by a plateau that gradually rises from left to right, corresponding to a decreasing efficiency from new plants (left edge) to older plants (right edge). Less efficient capacities require a higher amount of fuel per unit output, resulting in higher marginal costs.[7] If a market based regulation of CO_2 is introduced, compliance costs are added to marginal costs. Fig. 2.2 shows the modified German fossil merit order[8] with a carbon price of 15 €/t, which is fully added to variable costs (lighter shades indicate CO_2 costs).

It can be seen that the strict separation into coherent blocks dissolves. This happens because technologies with low fuel costs are disproportionally affected by CO_2 costs due to higher emission intensity, in particular lignite and hard coal. As a result, the least efficient plants of one technology block "change positions" with the most efficient plants of the block to the right. That is, old lignite overlaps with new hard coal, and old hard coal with new natural gas. In consequence, the general shape of the merit order also becomes flatter, and the discontinuities between different technologies dissolve.

Under this situation relevant changes accrue to (a) the overall price formation in the market and (b) the extent to which every single plant can sell to the market. The effect on prices (a) is global and emerges out of the increase of marginal costs in disproportion to fuel costs: the average level rises whereas the overall range is reduced due to the now flatter supply curve. The effect on generation (b) however is plant-specific: the modified marginal costs under CO_2 regulation may lead to a change of position of this plant in the merit order as explained above. In consequence, it can either increase or decrease its generation with a leftward or rightward shift, respectively.

Figs. 2.3 and 2.4 show the effect of new capacities in more detail. They depict the position of the assumed model plant alternatives in the merit order (red outlines). Without CO_2 pricing (Fig. 2.3), both plants are located at the left outer edge of their respective technology blocks and are relatively far apart. With CO_2 pricing however (Fig. 2.4), the blocks dissolve and the distance is reduced. This corresponds to a lower difference in annual full load hours Δflh, depending on the exact distribution of demand in between. Moreover, the flatter shape of supply under CO_2 pricing also reduces the total marginal cost differential Δmc between the two options.

This situation would arise if carbon prices were fully added to variable generation costs. If we neglect strategic behavior or inter-period constraints in electricity generation, it can be expected that rational market players pass-through CO_2 costs completely to electricity prices. This holds for the case in which certificates are auctioned, but also in a setting where permits are

[7] Natural gas plants include both gas turbines and combined cycle natural gas, which explains the jump in marginal costs within the gas block.

[8] In the following we will concentrate on the relevant fossil section of the merit order (lignite, hard coal, and natural gas) were all relevant effects take place.

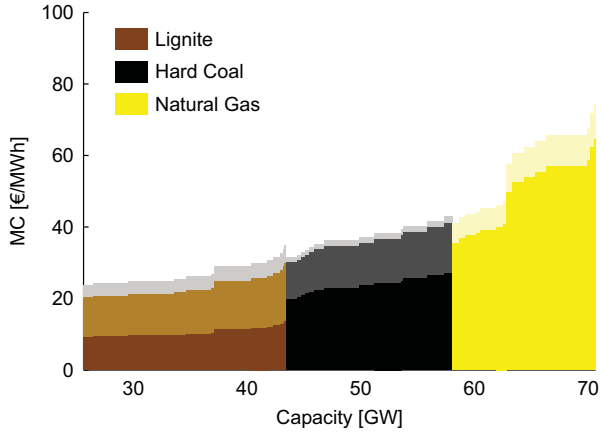

Fig. 2.5. German merit order (2005) with carbon costs of 15 €/t and flexibility-constrained cost pass-through.

grandfathered or allocated for free without ex-post correction. A profit-maximizing generator has to decide between (a) not generating electricity and selling the permits on the market, and (b) generating electricity and using the permits as a production factor. Generation will thus be an optimal choice only if the profit of generating electricity in case (b) does not fall below the profit of selling the permits in case (a). Accordingly, full pass-through is in principle a fully rational strategy.

Nonetheless, empirical analyses draw a different picture. For example, Sijm et al. (2006) show that pass-through rates in Germany reached 100% in peak times, but only around 60% in off-peak times.[9] In fact, agreement on the guiding rationalities for pass-through at lower rates than 100% is still pending; for a recent overview of arguments see Keppler and Cruciani (2010). Power plant owners may have a preference for generating electricity rather than selling permits, even if it is the less profitable alternative. Another explanation for incomplete pass-through may be that rates were chosen according to technical constraints, namely operating constraints and related costs. Whereas natural gas plants are very flexible, coal plants generally have considerable ramping and start-up constraints which also affect total plant lifetime (cp. Nollen, 2003). A coal generator may find it thus more profitable to sell electricity below marginal costs in a given period than to stop generation during this period and face the ramping-related costs. In order to fully capture this effect, it would be necessary to use a bottom-up electricity generation model which includes inter-period constraints. As this is beyond the scope of this article, we focus on technology-specific average pass-through rates that are constant over all hours of a year. We believe these annual average pass-through rates serve well to understand investment incentives over a longer period, as studied in this paper.

Following this line of argument, we assume that coal generators have a preference to retain their "old" position in the merit order. Lignite and hard coal operators set pass-through rates such that technology blocks persist and fuel switch is avoided. This corresponds to a merit order as shown in Fig. 2.5, in which shares not passed-through are indicated in light gray. It has been calculated by using the following heuristic: all gas plants are perfectly flexible and thus apply pass-through rates of 100%. The least efficient hard-coal plant chooses its pass-through rate such that it stays left of the most efficient gas plant. All other hard coal plants adjust their pass-through rates such that they stay left of the least efficient hard coal plant. The same procedure applies to the lignite plants. Performing this calculation for 2005 results in pass-through rates of 77% for lignite and 89% for hard coal.[10] Accordingly, generation technologies with lower technical flexibility have lower pass-through rates. Note that our rationale for asymmetric pass-through rates is based on technical considerations, not on market imperfections (cp. Fell, 2010).

The heuristic results in the merit order are shown by Fig. 2.5. In addition, we conduct a sensitivity analysis in Section 4.5 in which the pass-through rate is equal to 100% for all technologies. By doing so, we assess the sensitivity of results to our assumption on technology-specific pass-through rates.

2.3. Limitations

The main benefit of our approach lies in making several quantities endogenous, which both is a requirement for our research questions and increases plausibility. Nonetheless, the overall methodology has some shortcomings. There are a number of influencing factors not taken account of that affect generation, price formation and investment rationales in electricity markets. First, as Blyth (2010) and Pahle (2010) point out, in practice the uptake of a certain technology may be influenced by other factors like technological spillovers, additional regulatory biases, or the adherence to an established industrial structure. Second, on short time scales capacity outages, intermittent renewable generation, and ramping constraints lead to contractions and left-/rightward shifts of the fossil block in the overall merit order; also compare Weigt and Hirschhausen (2008). Third, over the course of the NPV evaluation period the market structure and generation mix are not static, but develop over time as new plants are built or old plants are decommissioned. Taking account of these would require a market investment model, which is both beyond the scope of this article and in many ways still considered as a challenge (see for example Lise and Kruseman, 2008). Consequently we only operate with a static snapshot of the generation mix in 2005, leaving future investments – even foreseeable ones – aside. And fourth, if the new plant would be built by a generator owning additional plants, then the investment would be optimized given the whole portfolio. Such investment decisions may fundamentally differ from the ones modeled here. We acknowledge this by restricting our model to only capture a single merchant plant as explained above.

In summary, claiming that the resulting NPVs would be the only criterion for deciding on an investment of a certain technology is beyond the potential of our approach. Rather, NPV differences can be understood as one of many contributing factors that we measure by means of the described methodology and its restrictions. Notwithstanding these limits, our intention is not only to quantify the overall outcome, but also to shed light on the micro dynamic effects within the merit order out of which the NPV differences emerge. In fact, because of the investment assessment in relative rather than absolute terms, we level out several of the described distortions as they apply to both hard coal and natural gas capacities. By doing so, we reduce the main element of our analysis to the section of the merit order that separates the potential new hard coal plant from the potential new natural gas plant,[11] namely the segment serving intermediate load. It is essentially this section that determines the difference in NPVs and explains the primary impact of free allocation vs. auctioning.

[9] Fell (2010) conducts an empirical estimation for the Nordic electricity market and finds that – in the short run – pass-through rates are close to 100% also in off-peak times.

[10] Thus rates found are here are somewhere between the findings of Sijm et al. (2006) and full pass-through. A higher CO_2 price assumption would result in lower rates closer to Sijm et al.

[11] In Figs. 2.1 and 2.5 for example, that section is identical to the full block of hard coal capacities.

Table 3.1
Annual allocations for model power plants (1000 MW) under NAP I and II.

	NAP I	NAP II
Hard coal	5.2500 Mt/a for 14 years (0.75 t/MWh × 7000 h × 1000 MW)	5.6250 Mt/a for up to 5 years (0.75 t/MWh × 7500 h × 1000 MW)
Natural gas	2.0075 Mt/a for 14 years (0.365 t/MWh × 5500 h × 1000 MW)	2.7375 Mt/a for up to 5 years (0.365 t/MWh × 7500 h × 1000 MW)
Distortion towards coal	3.2425 Mt/a	2.8875 Mt/a

3. Model application

3.1. EU ETS and German allocation rules

EU ETS allocation rules were implemented by National Allocation Plans (NAP) for Phase I (2005–2007) and II (2008–2012) respectively.[12] In Germany a so called "new entrant" reserve provided certificates to newly built capacity based on technology-specific benchmarks derived from the "best available technology" (BAT).[13] Both NAP I and NAP II define benchmarks of 0.75 tCO_2/MWh for hard coal and 0.365 tCO_2/MWh for natural gas, respectively (Bundestag, 2004, 2007). However, designs differ considerably with regard to how many years a new plant is entitled to receive free allocation. NAP I grants free certificates for 14 years after commissioning (see Åhman et al., 2007),[14] whereas NAP II restricts provisions to Phase II regardless of when exactly the plant started operation; it thus covers a maximum of five years only. In addition, the NAPs differ in their assumptions on plant utilization, which has an important impact on the actual number of certificates allocated to a plant. NAP I basically guarantees coverage of total annual emissions from power generation by considering the expected yearly production of a plant (Bundestag, 2004). Accordingly, new coal power plants receive more certificates than new natural gas plants not only explicitly due to higher technology-specific benchmarks, but also implicitly because of higher full load hours. In contrast, NAP II follows a less discriminatory approach by assuming 7500 full load hours per year for either technology. Table 3.1 provides an overview of the allocation for the model power plants (1000 MW).[15]

Considering that the value of emission certificates will be (partly) passed-through to customers, the new entrant provisions break down to a considerable economic advantage for hard coal due to the higher absolute allocations. The distortion was even higher in NAP I than in NAP II because of a longer duration and an allocation based on actual emissions. The relevant question thereby is whether the NAP revision induced a change in technology preference or retained the original one.

The German ETS was initiated with a pledge to generators guaranteeing free permit allocation to new plants for 14 years according to production needs (NAP I). Even though planning and constructing a power plant takes several years, early action and rapid realization could well have led to timely commissioning. Consequently, we use the total length (14 years) in the model application. Yet we do not restrict the analysis to the effects of the factual NAP I allocation, but also investigate investment incentives under the assumption that NAP II would have been applied from the beginning instead of NAP I. We also study the implications of two other counterfactual allocation rules: full auctioning (AUC) of all permits as well as the application of a single best available technology benchmark (SBAT), which explicitly favors carbon-efficient installations (Schleich et al., 2009). Under SBAT allocation rules, the extent of free permit allocation is determined by the requirements of the lowest-emission technology, i.e. natural gas plants. Such an approach was initially planned to be implemented in Germany, but policy makers finally decided to apply a technology-specific benchmark in NAP I, largely because of industry concerns (Ziesing et al., 2007). In addition, we analyze a case without CO_2 regulation (NoREG) in order to establish a reference case.

Under any allocation mechanisms, the price for CO_2 certificates is both an important model parameter and a crucial element for determining windfall profits. For our ex-post analysis, it is important which expectations investors had at the base year 2005 about the long-term price development. As the market was newly created and subject to many distortions, it all but provided a stable signal and forecasts were rather vague. In this regard Capoor and Ambrosi (2006) report that during 2003 and 2004 "forward trading mostly responded to political and regulatory expectations rather than to market fundamentals". In fact, early estimates mainly relied on what the EU was envisaging and communicating to stakeholders. In 2003 Point Carbon (2003) reported that the EU Commission indicated a level of 15 €/t. However, during the first emissions trading year 2005 it actually turned out that prices stabilized at 20–25 €/t. Regarding price development, Point Carbon (2006) concluded at the end of 2005 that the market already responded to the fundamentals of power generation, which possibly indicated future price increases in the same order of magnitude as fuel prices. As investors may well have anticipated additional pressure on the price through tighter political targets in the future, even higher expectations on price increases appear justified.

Following this argument and taking account of early signals, we assume an initial price of 20 €/t in 2005 and a yearly real growth rate of 2% in the baseline (cp. Table 3.4). In alternative scenarios, we assume a lower price path (15 €/t in 2005, +1% p.a.) and a higher one (25 €/t in 2005, +3% p.a.). These paths should cover many of the scenarios that actually existed on the investors' side. In particular, the implied extreme cases of around 18 and 45 €/t in 2025 represent the range of possible future emission prices widely discussed. It also should be noted that according to 2005 regulations we exclude the possibility of banking and borrowing certificates. Banking would have allowed investors to save up certificates that could be sold later on when CO_2 prices were higher. However, as discounting devalues banked certificates at higher rates (5–10%) than the increasing price of CO_2 would increase their value of (1–3%), banking would not have been an economic alternative whatsoever.

3.2. Fuel costs

In 2005 border trade prices for hard coal and natural gas were around 8 and 16€ per MWh_{th}, respectively (BMWi, 2010). Transport and trading mark-ups added, final costs for power generation

[12] Ziesing et al. (2007) and DEHSt (2009) provide excellent overviews of the development of German allocation rules and the related political debate.

[13] This approach contrasts with the grandfathering mechanism, which has been used for existing power plants, drawing on historic emissions.

[14] Later on, the European Commission decided that free allocation provisions of NAP I had to be restricted to the first ETS period. Nonetheless, we assume that investors in 2005 anticipated 14 years of free allocation. We further assume that there was no ex-post correction of free allocation, although this issue was not settled in Germany around the year 2005.

[15] We assume that new hard coal plants typically supply base load (about 7000 full load hours per year) and natural gas plants supply intermediate load (5500 full load hours per year), drawing on Konstantin, 2007.

amounted to 9.1 and 20.0€ per MWh_{th} (Konstantin, 2007). Regarding forecast, costs had already increased around 50% for both fuels between 2000 and 2005. According to the IEA World Energy Outlook (WEO), an increasing spread between coal and gas in long run price scenarios was expected around the year 2005. In the WEO 2004 reference scenario, hard coal prices were thought to increase by 16% until 2030 (annual price increase of +0.6%), while natural gas prices were projected to grow by around +27% during the same time (+0.9% p.a.) (IEA, 2004). Only one year later, IEA's expectations on hard coal prices dropped significantly to −7% until 2030 (−0.3% p.a.), while natural gas prices were projected to grow by even +33% during the same period (+1.1% p.a.) (IEA, 2005). We use these different price projections in alternative scenarios applying average yearly growth rates of +0.15% p.a. for coal and +1.0% p.a. for natural gas in the baseline (cp. Table 3.4).

As for other technologies than hard coal and natural gas, we assume zero fuel costs for renewable energy sources. This ensures that available renewable capacities are always operated (must-run) and represents priority feed-in according to the German Renewable Energy Sources Act (EEG). For peaker plants, which consist of oil and diesel plants as well as pumped hydro storage, we assume fuel costs of 100 €/MWh_{el} (compare Konstantin, 2007).[16] As a consequence, renewable sources are located at the very left side of the merit order, whereas peaker plants are at the very right side. Fuel cost for nuclear and lignite plants are around 3.5 €/MWh_{el} and 4.0 €/MWh_{th}, respectively.[17] We assume fuel costs for other technologies than hard coal and natural gas to be constant in all scenarios.

3.3. Capital and O&M costs

While economic conditions for fuel costs turned in favor of hard coal around 2005, capital costs developed in the very opposite direction. In 2004, specific investment costs were around 400 €/kW for natural gas and around 800 €/kW for hard coal capacity (Konstantin, 2007). Only two years later, costs had increased to around 500 €/kW for gas and 1100 €/kW for coal plants, mainly due to high global demand for power plants and increased prices for steel and copper (Konstantin, 2009). According to a study by trend:research, new hard coal capacity was even estimated to be as expensive as 1500 €/kW by 2007 (Flauger, 2007). This disproportionate growth in costs may have decreased the relative attractiveness of hard coal, and a number of projects especially by smaller suppliers have indeed been canceled due to this reason (see Pahle, 2010). The relevance of this development is also analyzed in Section 4, where we quantify the effect of increased capital costs (+50% for hard coal, +25% for natural gas).

It should be noted that our above assumptions refer to overnight costs, which do not comprise costs of financing due to either advance expenditures before construction (turn-key costs) or annuity based payoff (fixed charge rates). Both schemes imply additional interest on capital, and thus would require calculating final investment costs based on the discount rate. Even though this is in general more realistic, it is also very specific to both projects and investors and thus hard to implement properly (see Section 3.6). That said, and in face of our focus on allocation schemes, we ignore the details on how the investors finance the project and thus how the capital cost is paid off. This approach is in line with standard cost assumptions for electricity modeling.

Table 3.2
Net available capacities of different generation technologies.

Technology	Capacities (in GW)	Cumulated capacities (in GW)
RES	7.1	7.1
Nuclear	18.4	25.6
Lignite	17.8	43.3
Hard coal	13.7	57.0
Natural gas	12.6	69.6
Peaker	8.4	78.0
Total	**78.0**	

Aside from investment costs, we consider fixed costs for operation and maintenance (O&M) in the model application. We assume yearly O&M costs of 37.8 €/kW for hard coal and 30.3 €/kW for natural gas in the baseline run (Konstantin, 2007).

3.4. Generation capacities

For the conventional fossil supply structure of the German market, we draw on public data provided by UBA (2009).[18] We exclude combined heat and power plants for which the merit order dispatch mechanism is not applicable due to heat-controlled operation. In total we consider 150 conventional fossil plants, out of which 52 are lignite, 50 are hard coal, and 48 are natural gas. The overall installed gross capacities are 20.8, 19.0 and 12.8 GW, respectively. We derive net available generation capacities drawing on average plant availabilities and other technology-specific factors provided by Konstantin (2007). The thermal efficiency is derived on a plant-by-plant basis according to an age-efficiency correlation established by Schröter (2004).

In addition to fossil capacities, the overall supply structure also includes nuclear, renewable and peaker plants. We derive the nuclear capacity of 2005 and its average net availability from the sources mentioned above (Konstantin, 2007; UBA, 2009). As for renewables, their overall installed capacity amounted to 27 GW in 2005 (BMU, 2006). Due to the high share of wind, we only consider average annual availability, which amounts to approximately 7 GW. Peaking capacity consisted mainly of oil and pumped hydro plants (UBA, 2009). Table 3.2 lists the available net generation capacities of all included technologies. These capacities form the merit order based on ranked short-run marginal costs, which is shown in Fig. 2.1.

3.5. Demand

For demand assumptions we draw on load data provided by ENTSO-E (2010).[19] Fig. 3.1 shows both the distribution of hourly loads in the German network and cumulated load hours for different demand levels. Demand ranged from around 33 GW to a peak value of 78 GW. In order to determine the marginal plant and thus the price of electricity for every hour of the year, we align the load distribution and the merit order derived from the generation capacities listed in Table 3.2. We find that demand fluctuations span from lignite over hard coal and natural gas up to the peaker plants. Thus RES, nuclear and some lignite plants are always in operation, which resembles the real market very well. To compare our model with empirical operational characteristics

[16] The exact price level is not relevant for the modeling results as it levels out by only looking at relative NPVs.

[17] Note that fuel costs for renewables, peaker technologies, and nuclear power plants are related to electricity generation; while fuel costs for all other technologies are related to the thermal energy content.

[18] We only consider plants that were commissioned before 2005.

[19] We use data for 2006, since data for 2005 is not available. It is reasonable to assume that German electricity demand pattern did not change significantly between 2005 and 2006. ENTSO-E was formerly known as the Union for the Co-ordination of Transmission of Electricity UCTE.

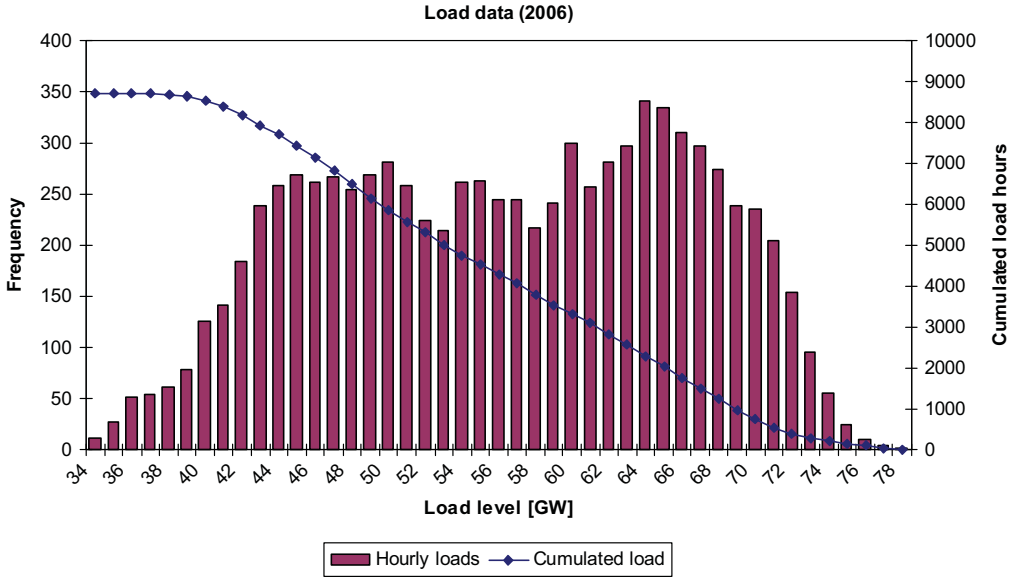

Fig. 3.1. Load distribution in 2006 (ENTSO-E, 2010).

Table 3.3
Estimated model full load hours and empirical values for 2004 for different fossil technologies.

	Model full load hours (averages)	Empirical full load hours 2004 (VGB PowerTech, 2005)
Lignite	7410	7230
Hard coal	4748	4460
Natural gas	2424	2730

of fossil power plants, we use cumulated load frequencies to estimate average full load hours for the installed plant capacity of each technology. As shown in Table 3.3, they fit empirical values for 2004 provided by VDEW (cited in VGB PowerTech, 2005)[20] quite well.

Due to unavailability of data for all hours of the year we excluded cross-border trade with other countries; both exports and imports in 2005 were in the order of 10% of total generation, while the net balance was small. However, this should pose only a minor problem since we focus on the relative profitability of two investments, such that deviations from the real world cancel out. Including trade would be much more relevant in an analysis that aims to reproduce real hourly market outcomes, as for example in Weigt and Hirschhausen (2008). Furthermore we explicitly aimed to improve the methodology used in similar studies in the gray literature. For example, Garz et al. (2009) only make use of five characteristic demand levels, by which they try to capture daily fluctuations. In doing so they neither describe a method for finding particular levels, nor do they crosscheck resulting full load hours to empirical data. In contrast to this approach we conjecture our representation as considerably more grounded in empirical facts.

With regard to the future development, we assume that demand persists at the 2005 levels for mainly two reasons. First, we can only speculate about growing or falling demand for the next years. There are good reasons for future trends in both upward (economic growth, substitution of other energy carriers by electricity) and downward (energy efficiency, elasticity to higher prices) direction. Second, even if demand changes to some extent, it is unlikely to affect our results, because we only look at NPV differences. These differences are solely determined by the section of the demand distribution that is located between the coal and the gas plant. As indicated by Fig. 2.1, coal and gas are located at the center of the demand distribution that is relatively even. Hence a moderate shift in one or the other direction would not change results much.

3.6. Discount rates and financial lifetime

Net present value calculations require using a discount rate. It reflects the time value of money or the rate of return if the capital is invested in alternative projects, and also comprises a project specific risk mark-up. Thus it depends on specific projects and is generally hard to estimate empirically (Rust, 1987; Timmins, 1997; Ishii and Yan, 2004). In this context, we draw on a standard discount rate assumption for investments in electricity generation capacities of 7.5%. It represents the mean value of 5% and 10%, which are used by the International Energy Agency (2010). These rates seem commonly agreed; for instance Fleten et al. (2007) and Patino-Echeverri et al. (2009) use 5%, whereas Gross et al. (2010) use 10%. The financial lifetime, over which cash flows are considered, is assumed to be 20 years in the baseline (compare Lindenberger and Hildebrand, 2008).[21]

Table 3.4 provides a summary of all model parameters. Fixed costs (specific investment and O&M costs) are listed only for hard coal and natural gas plants, as we analyze investments in these technologies only. Fuel costs are provided for lignite, hard coal, and natural gas. For renewable, nuclear and peaker technologies, we use overall variable cost of electricity generation (c_{el}) in order to simplify the analysis.

[20] We use data for 2004 because from 2005 on empirical full load hours already reflect the impact of certificate pricing.

[21] For reasons of comparison, we neglect the fact that gas plants generally have lower financial life times than hard coal plants.

Table 3.4
Overview of model parameters. Real numbers, monetary value 2005.

Parameter	Baseline	Alternative scenarios	Source
T_{FL} in years	20		Own assumptions drawing on Lindenberger and Hildebrand (2008)
$T_{FA} \subseteq T_{FL}$ in years $T_{AUC} \subseteq T_{FL}$ in years	NAP I: 14 NAP II: 5 NAP I: 6 NAP II: 15	0–20 years of free allocation, full auctioning (AUC) or single best available technology (SBAT)	Bundestag (2004, 2007)
$cap(k)$ in MW	Hard coal: 1000 Natural gas: 1000		Own assumptions
$c_{cap}(k)$ in €/kW	Hard coal: 800 Natural gas: 400	Hard coal: 1200 (+50%) Natural gas: 500 (+25%)	Rounded from Konstantin (2007), own assumptions (see Section 4)
$c_{OM}(k)$ in €/kW	Hard coal: 37.8 p.a. Natural gas: 15.5 p.a.		Konstantin (2007)
$c_{el}(k,t)$ in €/MWh$_{el}$	RES: 0 Nuclear: 3.5 Peaker: 100.0		Konstantin (2007), IEA (2004, 2005), own assumptions
$p_{fuel}(k,t)$ in €/MWh$_{th}$	Hard coal: 9.1 (2005), +0.15% p.a. Natural gas: 20.0 (2005), +1.0% p.a. Lignite: 4.5 (2005), 0% p.a.	Hard coal: +0.6%/−0.3% p.a. Natural gas: +0.9%/+1.1% p.a.	Konstantin (2007), IEA (2004, 2005), own assumptions
$p_{CO2}(t)$ in €/t	20.0 (2005), +2% p.a.	15.0/25.0 (2005), +1% p.a./+3% p.a.	Point Carbon (2006), own assumptions
$\eta(k)$	Existing hard coal plants: 32.7–44.3% Model hard coal plant: 46% Existing natural gas plant: 31.2–56.0% Model natural gas plant: 58.0%		UBA (2009), Schröter (2004), Wietschel et al. (2010)
$cef(k)$ in t/MWh$_{th}$	Hard coal: 0.342 Natural gas: 0.202 Lignite: 0.410		Konstantin (2007)
δ	7.5%	5%/10%	IEA (2010)

4. Results

4.1. Overview

We first compare investment incentives in the reference case without regulation (NoREG) with the factual allocation rules (NAP I) and three possible counterfactuals, all evaluated over 14 years[22]: NAP II, full auctioning (AUC) and a technology neutral single best available technology benchmark (SBAT). Considering later developments and insights by policy makers, it is useful to contrast the results of the factual allocation to the results of counterfactual schemes. Second, we investigate the sensitivity of results to fuel prices and capital costs. Third, we compare the interdependent effects of free allocation period length and size of the discount rate on NPVs. And finally, we examine the sensitivity of results to our assumption of asymmetric cost pass-through.

4.2. CO_2 regulation under different allocation rules

A baseline run without any carbon regulation (NoREG) shows that a hard coal plant is € 283 million more profitable than a natural gas plant. Thus hard coal plants would have been the preferred investment choice around 2005. The situation changes considerably after the introduction of the ETS, as shown in

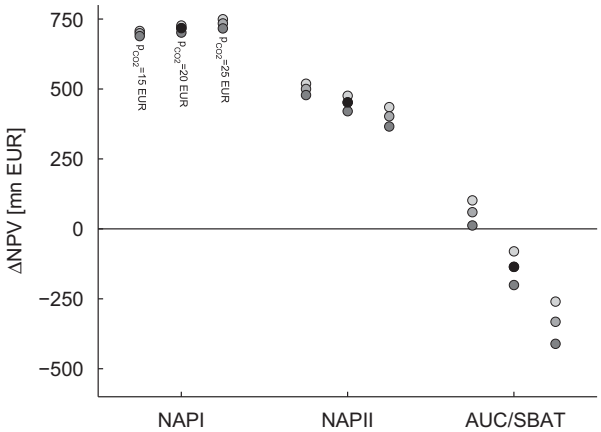

Fig. 4.1. NPV differences between hard coal and natural gas investments for different allocation rules and CO_2 price expectations. Lighter shades indicate lower annual CO_2 price increases.

Fig. 4.1. In the NAP I case, which represents the factual allocation rules by then, hard coal's NPV edge over natural gas increases substantially relative to the reference case. Under baseline assumptions (black dots), a hard coal plant is € 717 million more profitable than a comparable natural gas plant. The respective increase in the NPV difference of € 434 million originates from

[22] We assume 14 years according to the free allocation period length originally envisaged in 2005 (see Section 3.1).

Table 4.1
NPV differences between coal and natural gas plants in million € for different allocation rules and price assumptions (base cases in bold).

				Annual hard coal price inc. [%]								
				−0.3			0.15			0.6		
				Annual natural gas price inc. [%]								
				0.9	1	1.1	0.9	1	1.1	0.9	1	1.1
NAP I	*CO_2 price (2005) [€]*		*Annual CO_2 price inc. [%]*	1	738	759	782	686	707	729	631	653	675
		15		2	730	751	773	677	699	721	623	644	667
				3	719	741	763	666	689	711	613	634	656
				1	759	780	802	706	727	750	652	674	695
		20		2	748	770	791	696	**717**	739	641	663	684
				3	733	754	777	682	701	725	627	649	670
				1	778	800	822	726	749	772	672	694	715
		25		2	765	787	809	713	734	756	660	681	702
				3	747	769	791	696	717	740	641	663	685
NAP II	*CO_2 price (2005) [€]*		*Annual CO_2 price inc. [%]*	1	550	571	593	497	519	540	443	465	486
		15		2	530	552	574	478	500	522	424	445	467
				3	508	530	552	456	478	500	402	424	446
				1	507	529	550	455	476	498	401	423	444
		20		2	483	504	525	430	**452**	473	375	398	419
				3	453	473	497	401	421	444	346	368	389
				1	464	486	508	412	435	458	358	380	401
		25		2	434	456	477	381	402	425	328	349	370
				3	396	418	441	345	366	389	290	312	334
AUC & SBAT	*CO_2 price (2005) [€]*		*Annual CO_2 price inc. [%]*	1	133	154	176	80	102	123	26	47	69
		15		2	90	111	133	38	59	81	−17	4	27
				3	42	64	86	−10	12	34	−64	−42	−20
				1	−49	−27	−6	−101	−80	−58	−156	−134	−112
		20		2	−105	−83	−62	−157	**−136**	−114	−212	−190	−169
				3	−169	−148	−125	−221	−201	−178	−275	−253	−232
				1	−232	−209	−187	−283	−260	−237	−337	−316	−294
		25		2	−301	−279	−258	−353	−332	−310	−407	−386	−364
				3	−380	−359	−336	−432	−411	−388	−487	−464	−443

disproportionate windfall profits related to technology-specific allocation rules.[23] Applying the counterfactual NAP II allocation rule, the NPV difference increases less pronounced than under NAP I rules to only € 452 million. This is essentially due to the non-discriminatory full load hour approach of NAP II (compare Section 3.1). In the counterfactual case with full auctioning (AUC), the picture changes. The natural gas plant now has a comparative advantage of around € 136 million. We find the same NPV difference for the SBAT case, in which a single best available technology benchmark is applied. In contrast to AUC, SBAT creates windfall profits. However, it does so to the same extent for both technologies. Hence absolute NPVs increase, but the NPV difference remains equal.

Additional model runs show that some allocation rules are highly sensitive to CO_2 price assumptions as shown in Fig. 4.1. Whereas the NAP I and NAP II cases are relatively robust, the AUC and SBAT regimes are strongly affected by varying assumptions. For example, in a scenario with very low CO_2 prices, the relative NPV advantage of hard coal under AUC/SBAT is € 102 million. Under the same allocation rules, natural gas investments achieve a NPV edge of € 411 million over hard coal in the case of a high CO_2 price path. In general, increasing CO_2 prices support natural gas investments under AUC/SBAT – as intended by carbon regulation. Yet under NAP I, higher carbon prices slightly increase hard coal's NPV advantage due to higher windfall profits. Our results thus underline that the introduction of emissions trading may lead to perverse outcomes if allocation rules are not carefully chosen.

[23] Note that € 434 million account for around half the capital costs of the model hard coal plant.

4.3. Sensitivity to fuel prices and capital costs

As expected, results are also sensitive to fuel price paths with the effect that higher fuel prices for a particular technology decrease the NPV difference to this technology's disadvantage (see Table 4.1). Under NAP I and NAP II, different assumptions do not challenge hard coal's NPV edge over gas investments though. Yet in the AUC and SBAT cases, varying fuel price assumptions can result in a change of investment decisions, but only when the lowest CO_2 price path applies.

We now look at overall sensitivities of results to fuel and CO_2 prices. Under NAP I and NAP II, even the most extreme values for the NPV difference are relatively close to the baseline outcome and are well in the positive range. That is, the investment preference for hard coal under NAP I and II is very robust. In contrast, fuel and CO_2 price sensitivities in the AUC and SBAT cases are both more significant and lead to sign changes of the NPV difference. As a matter of fact, emission regulation only unfolds its intended incentives in these schemes. And, given the range of sensitivities under either scheme, CO_2 prices pose a higher risk on profitability than fuel prices, which were the previously dominant factors in this respect.

Finally, we examine the effect of increasing capital costs on NPV results. Capital costs of thermal plants have risen considerably during the last years, in particular for coal (see Section 3.3). Higher capital costs partially offset windfall profits gained through free allocation. We quantify this effect by increasing capital costs +50% for hard coal, and +25% for natural gas. As investment costs are fixed and incur only at the initial period, the sensitivity analysis is straight forward. Under the new assumptions, the difference in total capital costs is increased by € 300 million, which directly translates into an NPV difference of equal

size. As Table 4.1 shows, this reduces the relative advantage of hard coal over gas projects to € 417 million under NAP I baseline assumptions. Even in the worst case, the NPV difference is still very large (€ 313 million). That is, hard coal projects retain a considerable NPV edge over natural gas under NAP I even in the light of higher capital costs. The same is true for NAP II. Yet under alternative allocation regimes like AUC and BAT, higher capital costs would have made natural gas plants the preferred investment choices in all scenarios analyzed here.

4.4. Free allocation period length and discount rate

In general a higher discount rate puts more weight on early cash flows, thus reducing the benefits of long-term schemes. For example, in this case with a payoff time of 20 years, 5% and 10% discounting lead to a cumulated weighted cash flow of 62% and 72% respectively after ten years already. Accordingly, there is a joint impact of free allocation period length and discount rate on profitability. The length of the free allocation period was a highly discussed policy variable at the time of NAP I discussions. The question arises if there is a turning point in duration from which on the investment distortion may invert. For the case of Germany this implies an answer to the question if a shorter free allocation period, probably in combination with higher discounting, could have created a dedicated incentive for natural gas.

Fig. 4.2 shows the results for varying discount factors and allocations lengths (2, 4, 6,…, 20 years, lighter to darker shades). An apparent observation is the respectable impact of different lengths in the NAP I and NAP II case, which results in much larger NPV variations than the previously analyzed CO_2 and fuel price sensitivities. The length of the free allocation period has a substantial impact on the NPV difference between coal and gas investments: in the most extreme cases it rises as high as € 1216 million (NAP I, 20 years, 5%) and as low as € −69 million (NAP II, 2 years, 10%). This is mainly due to the resulting reduction of windfall profits, which are higher for coal than for gas, and thus reduce coal's NPV edge over gas. Higher discounting works in the same direction: it reduces total future cash flows, but leaves upfront capital costs untouched. Due to the higher capital intensity of hard coal compared to natural gas, this reduces hard coal's profitability to a greater extent. Still, the NPV difference remains always positive for NAP I and NAP II except for three extreme cases. Accordingly, hard coal investments remain more

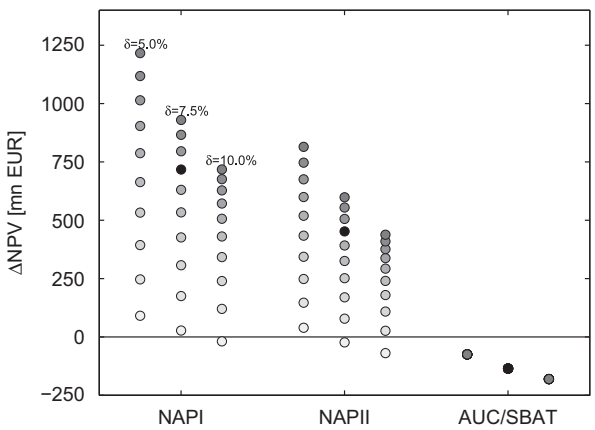

Fig. 4.2. NPV differences between hard coal and natural gas investments for different allocation rules, allocation lengths and discount rates (base case assumptions for fuel and CO_2 prices).

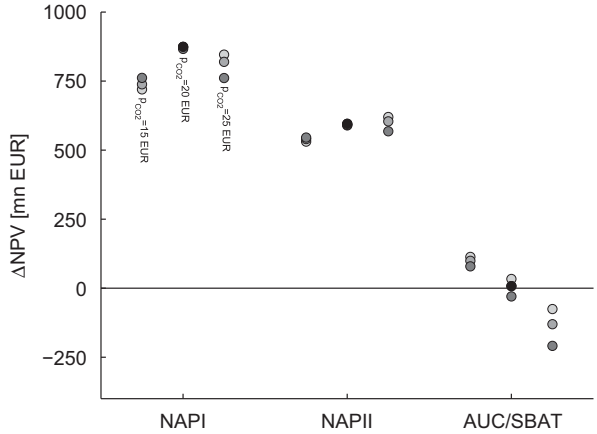

Fig. 4.3. NPV differences between hard coal and natural gas investments for full cost pass-through.

profitable than natural gas investments in almost all NAP I/NAP II variations.

The situation is utterly different for the AUC/SBAT cases though. Here it turns out that the length of the free allocation period (SBAT) does not matter. The reason is basically the same as given above for why AUC and SBAT produce identical NPV differences: due to equal allocations, both technologies profit to the same extent given a certain allocation period length. The discount rate plays a role though, but only a minor one. In summary the distinct investment incentive for natural gas provided by AUC/SBAT remains unchanged.

Hence varying policy length has a considerable impact on relative profitability if certificates are allocated in a technology-specific way (NAP I, NAP II). In contrast, there is no influence at all if allocation is technology neutral (SBAT). In the German case, a different allocation period length under NAP I would not have mattered, as pre-existing economic advantages for hard coal were too strong.

4.5. Sensitivity to asymmetric pass-through rates

The results discussed so far draw on technology-specific pass-through rates, which are heuristically determined as explained in Section 2.2. We assess the sensitivity of results to the assumption of asymmetric pass-through rates by re-running the model while assuming full pass-through for all technologies in all periods. Fig. 4.3 shows the resulting NPV differences: the main outcomes do not change. However, the relative profitability of hard coal increases in all cases compared to asymmetric cost pass-through (compare Fig. 4.1). This result should be expected, as hard coal plants are no longer "forced" to sell electricity at prices slightly lower than their full marginal costs – including full opportunity costs of emission permits – during some periods. As a consequence, natural gas' NPV edge over hard coal vanishes under full auctioning or SBAT.

The results also show that adjusting pass-through rates to avoid fuel switch is actually not an optimal strategy for hard coal generators. Under NAP I allocation rules and baseline assumptions, for example, using asymmetric pass-through rates instead of full pass-through leads to losses of € 157 million over the lifetime of the hard coal project. Still, as discussed earlier, there is empirical evidence that asymmetric pass-through occurred. Ramping-related technical constraints which incur additional costs provide a possible rationale (see Section 2.2).

5. Conclusions

We have studied the distortionary effect of different emission permit allocation rules on fossil power plant investment choices in Germany. We explicitly take into account windfall profits and perform sensitivity analyses regarding fuel prices, capital costs, the length of the free allocation period, and discount rates. To our knowledge, this article is the first to quantify the investment distortion towards hard coal created by the German NAP I implementation. We also make a methodological contribution to the literature by combining DCF analysis with a merit order approach, which allows determining electricity prices and plant utilization endogenously. Furthermore, we explicitly consider technology-specific asymmetric pass-through rates.

We find that without carbon regulation, investments into hard coal power plants had a significant NPV edge over natural gas in 2005. This finding may explain why so many hard coal projects were initiated around the time. Introducing regulation has a large impact on NPVs of fossil investments in general, but magnitude and direction of effects heavily depend on allocation rules. Under the factual scheme of 2005 (NAP I), the preference for emission-intensive coal investments, which was prevalent even without carbon regulation, was greatly increased by expected windfall profits. We further find that the length of the free allocation period – heavily discussed at that time – has an important impact on the relative profitability of coal and gas investments. Nonetheless, even the shortest lengths would not have provoked a change in technology choice, notwithstanding three extreme cases. We thus conclude that the particularly long period of free allocations granted in NAP I played a less important role than initially assumed.

Our investigation of counterfactual allocation rules shows that an alternative implementation of NAP II in 2005 would not have changed the overall picture. In contrast, applying full auctioning or a single best available technology benchmark – as initially planned – could have halted or even reversed the "dash for coal", depending on fuel and CO_2 price paths. While both options lead to the same relative outcomes, they differ with regard to absolute investment incentives. According to our results, full auctioning would have substantially decreased the profitability of hard coal projects compared to the case without carbon regulation. In contrast, single best available technology allocation would have increased the profitability of both hard coal and gas projects due to windfall profits, while natural gas would have benefited more.

We conclude that the German NAP I did not cause the "dash for coal" in the first place, but greatly spurred and sustained it. While German policy-makers intended not to hamper investments in the power sector by carbon regulation (Matthes and Schafhausen, 2008), they designed an allocation scheme which in the end created perverse incentives and massively promoted investments into emission-intensive hard coal plants. Obviously, policy makers failed to take the effects of free allocation-related windfall profits on coal profitability into account. We have thus shown that the details of implementing carbon regulation can be extremely relevant in a dynamic perspective. Different allocation regimes may not just have distributive effects, but also important consequences for investment choices.

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Chapter 4

Investments in Electricity Markets with Imperfect Competition: Technology Choice and Optimal Carbon Pricing*

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Investments in Electricity Markets with Imperfect Competition: Technology Choice and Optimal Carbon Pricing

Abstract: This study addresses the question how investments in imperfectly competitive electricity markets are influenced by a price on carbon. The particular details investigated are: (1) What is the interaction between investments and short-term market power in generation in the context of our model? (2) Which technologies are pulled into the market at what carbon price? (3) What is the optimal carbon price level given certain social costs of carbon emissions? The analysis is based on a case study of Germany using a numerical game-theoretic Cournot model. In contrast to other models, we include a relatively detailed representation of demand and fluctuating wind energy availability, and allow for endogenous capacity decommissioning. Motivated by recent empirical investment findings, we also restrict the use of hard coal for new investments to strategic players. Our main results are that market power triggers the entry of natural gas in the market at a lower carbon price compared to perfect competition. Furthermore, for higher carbon prices investments are exclusively in natural gas, which makes the market more competitive on the whole. From a welfare perspective, losses due to market power are relatively low and do not exceed 1% for all analyzed cases.

1. Introduction

It is widely accepted that combating global climate change requires a large-scale transition of the energy system towards lower carbon intensity. As part of this process electricity supply is a relevant sector to address, mainly because of the availability of technologies with high potential for low cost abatement in the long run; see for example Edenhofer et al. (2009). In order to transform electricity supply, investments in new capacity are a key figure, and incentives are needed so as to direct them towards "cleaner" technologies. In the EU the main instrument conceived for doing so is a price on carbon (EC 2006). An important prerequisite is that markets are capable to induce investments efficiently in the first place. This, according to the EC (2006), requires a fully functioning and competitive market.

When looking at member states' markets though, mergers and acquisitions, barriers for new entry, and political backup of national champions have often increased concentration or sustained monopolies. In Germany – the case we study here – the four largest suppliers (RWE, E.ON, Vattenfall and EnBW) operate around 80% of all conventional capacity in the market, and nearly 100% of all base load plants (lignite and nuclear) therein. This raises concerns about the exertion of market power, most prominently brought forth by an extensive sector inquiry conducted by the European Comission (EC 2007). In the course of investigations that followed, E.ON for example offered to divest a share of its capacity (EC 2008), presumably to avoid succeeding trials. There is also support in the scientific literature: for example Weigt & v. Hirschhausen (2008), using a simplified benchmark model, find that prices are above the competitive levels for a large number of observations. However, there are also studies that contest this assertion. ESMT CA (2010) finds that other markets in Central Western Europe are more and more competitively interlinked with the German, which implies that no dominating suppliers on the national level exist. Furthermore, a recent study by the German cartel authority (BKartA 2011) also finds no evidence for price manipulations for the years 2007-2008. It concedes that such manipulations were possible though, given the high shares of capacities owned by incumbent firms; Ehlers & Erdmann (2007) arrive at the same conclusion. In summary, a definite conclusion about the exertion of market power can not be drawn. Nevertheless, we will assume strategic behaviour by the four large suppliers as a working hypothesis for our analysis, and compare it to the case of perfect competition when discussing results.

Of particular interest in this study is that the exertion of market power in generation may also considerably affect the size of investments and technology choice. Even though there is a large body of literature dealing with market power in generation – e.g. Green & Newberry (1992), Neuhoff et al. (2005), Willems et al. (2009), Schill & Kemfert (2011) – this particular aspect has hardly been analyzed so far. More precisely, when large firms make investments in new plants or decommission old plants, they potentially add or remove a non-negligible share of the overall available capacity. By doing so, the supply curve may be changed substantially, which in turn also affects the operation and profitability of all other plants in the market. In particular suppliers that operate a number of plants may thus raise the value of their overall portfolio. Such behaviour has been analyzed for example by Arrelano & Serra (2007) and Zoettl (2008). Most interestingly both articles arrive at different results indicating two relevant mechanism at work. Zoettl (2008) finds that there is a tendency to overinvest in base load capacities, by which market prices are reduced on average and competitors' investments are reduced. On the other side, Arrelano & Serra (2007) conclude that "generators can obtain rents by increasing the share of peaking technology in the generation portfolio", by which market prices are increased in average. Thus strategic players have potential incentives to both increase (portfolio rents) and decrease (entry deterrence) the market price at the same

time. However, these results depend on the particular structure and parameters of the used models and it is unclear if the widely employed Nash-Cournot approach we use in the present study (see below) shows similar behaviours. Moreover, effects presumably depend on initial capacity endowments and market fundamentals, and this justifies a study of this issue calibrated to a particular case – in contrast to the aforementioned stylized analyses. This aspect is addressed in Section 4.1.

A second important aspect we focus on relates to the incentives to shift investment towards lower carbon intensive technologies due to the carbon price. In general additional costs incurred for carbon emissions favour the use of less carbon intensive fuels and thus should trigger according investments. Given available technologies and their cost structures, the main expected effect is the substitution of coal with natural gas. In that respect a relevant interaction with market power can occur with possible strategic investments outlined above: if existing it may enhance suppliers' tendencies to increase the share of peaking technology (natural gas). But it may also decrease the contrary tendency, namely to overinvest in baseload capacities (coal), thereby counteracting the original effect of market power on investments. We deal with this issue in Section 4.2.

The potential influence of market power on investments becomes all the more important when considering the current situation in the German market. As pointed out by Pahle (2010), investments in coal power plants during the last years were nearly exclusively made by the four largest suppliers in the market, mainly due to financing reasons. On that ground we assume that this technology is exclusively available to the strategic players. This extends market power to a technological dimensions and thus creates an additional advantage for incumbents, which nevertheless may dwindle under the impact of the carbon price for the above reason[1]. Hence this is another issue to focus on in our analysis.

Finally, the interactions of market power and carbon pricing has severe welfare implications. This raises the question how a government should set the carbon price optimally with respect to social welfare if this is the only available instrument[2]. In general the literature states that in case of market power the optimal price should be below the Pigouvian level; see for example Ebert (1992) and Marschinski (2010). The main impact, a relative increase in output to counteract the effects of market power, has to be balanced with increasing emissions though. In particular we quantify the optimal levels for different social costs of carbon, which also allows us to inspect the more general properties of the regulatory solution space. This is shown to provide valuable insights regarding the question to which extent – in case of misinformation about market power – wrongly applied instrument levels reduce overall welfare. Moreover, it allows us to asses if under high carbon prices the impact of market power actually dissolves (see above), which we investigate in Section 4.3.

We base our analysis on a numerical model calibrated to the German electricity sector. The de facto standard for models that include market power are Nash-Cournot games; compare Ventosa et al. (2005). Most widely applied are certainly the dynamic versions of the EMILIE model that include investments; see for example in Lise et al. (2006), Lise & Kruseman (2008), and Traber & Kemfert (2011b). The core model has been continuously developed and improved over the last years, and proved helpful for analyzing several important policy questions. Notwithstanding all its advantages, the model also has its shortcomings. First,

[1] In contrast, recent theoretical research indicates that such settings can decrease overall welfare if markets are competitive (Meunier 2010).
[2] As pointed out by Traber & Kemfert (2010), an output subsidy could be used as a second instrument. However, we concentrate on the instruments currently in place, i.e. a price on CO_2 emissions.

existing capacities are decommissioned if they reach the end of their technical lifetime, and not out of economic considerations. This can be extremely important though when investigating the effects of emission pricing, and has also been shown to be the main driver for plant closure (Nollen 2003). Second, the EMILIE model has a relatively rudimentary representation the fluctuations of demand and wind energy supply. In Lise & Kruseman (2008) for example only two different load periods are used, and wind variability is apparently not accounted for. Such a calibration may well serve as a first estimate, but ignores relevant technical intrinsicalities. Traber & Kemfert (2011a) use hourly data, but only look at investments incentives and do not consider actual investments endogenously in their model. We fill these gaps with our model, albeit this happens at the expense of other features like linked markets and network constraints. But doing so also allows us to inspect the technological implications, which are an important policy issue by themselves.

The rest of this paper is structured as follows: in Section 2 we develop the modelling framework, which is then calibrated to Germany in Section 3. In Section 4 we investigate the technological and economic impacts of CO_2 pricing and conduct the welfare analysis. In Section 5 we conclude and discuss results.

2. Methodology & Model

In order to concentrate on the main effects and keep the model analytically tractable, we employ a quasi-dynamic approach with only two time steps similar to Fan et al. (2010). During the first period ("now", 2010) players make their investments based on the maximization of expected profit in the second period ("future", 2020), which extends over one year. By doing so we assume that this single year is somehow representative for the whole time horizon that investors consider for their planning. Following this logic we have chosen a 10 year look in the future, which is halfway to typical planning periods extending over 20 years. This may actually resemble the investment environment for the next generation of capacity additions very well.

The basic setup of the model conforms to the typical structure of Nash-Cournot type electricity market models; see Ventosa et al. (2005). The short-term (future) decision variable of each player (i) is generation (q_{ijkl}) using available capacity of technology (k) and vintage (l) in each demand period (j). Multiple periods are used to account for intra-annual demand fluctuations, and are characterized by their duration in hours (h_j) and linear inverse demand functions relating overall generation to electricity price:

$$(1)\ \ p_j(\overline{q}_j) = P_{0j} - \frac{P_{0j}}{Q_{0j}} \cdot \overline{q}_j\ ;\ \overline{q}_j = \sum_{i,k,l} q_{ijkl}$$

Generation is limited up to the available total capacity (cap_{ikl}), which is modified by an availability factor (af_k). This technology specific factor ranges from 0 to 1 for intermittent renewables, wind in this paper, and is set to 1 otherwise. Thus it represents the relative availability of the energy source at each period j.

$$(2)\ \ q_{ijkl} \le af_k \cdot cap_{ikl}$$

As mentioned above, technologies are classified into vintages to differentiate between existing and new capacities (see Table 2.1). The zero vintage ($l=0$) represents the upcoming generation of plants, i.e. investments (I_{ik}) in state-of-the-art technologies with no currently existing capacities ($cap_{0,il0}=0$). All other vintages ($l=1,2,3,4$) represent existing capacities ($cap_{0,ikl}\ge 0$) of different plant age groups, which can be decommissioned (D_{ikl}) in order to optimize a player's generation mix (see below). A particular feature of the model is that investments are limited to technological options available to a specific player (K_i). Altogether investment and decommissioning are the players' long-term decision variables resulting in the final capacity

$$(3)\ \ cap_{ikl} = cap_{0,ikl} + I_{ik} - D_{ikl} = \begin{cases} I_{ik} & k \in K_i\ ,\ l = 0 \\ 0 & k \notin K_i\ ,\ l = 0 \\ cap_{0,ikl} - D_{ikl} & l = 1..4 \end{cases}$$

subject to

$$(3^*)\ D_{ikl} \le cap_{0,ikl}$$

Vintage (l)	Plant age
0	(investments)
1	1-10 years
2	11-20 years
3	21-30 years
4	30+ years

Table 2.1: Vintages

For some technology options (K_i*) it is necessary to restrict investment because resource availability only allows a limited amount of annual extraction. In that case we assume that newly built capacity must be equal or less than the sum of all decommissioned old capacities of this fuel type. This condition implies that the total capacity never exceeds its initial size and is expressed by:

$$(3^{**})\ I_{ik} \le \sum_l D_{ikl} \quad \forall i,k \in K_i^*, l = 1..4$$

Building new capacity incurs capital costs ($c_{cap,k}$), while the availability and operation of (all) plants incur fixed O&M costs ($c_{OM,kl}$). In fact, fixed O&M costs are the sole reason to decommission old capacity not used for generation, which otherwise would be used solely during peak demand time. Such exclusive use in peak times is not observed in real markets though, and hence such a mechanism seems appropriate. Apart from fixed costs, fossil and nuclear generation incurs variable fuel costs ($c_{fuel,k}$), which in the case of fossil power depend on thermal efficiency (η_{kl}). The overall profit of each player thus reads

$$(4)\ \Pi_i = \sum_j \sum_{k,l} (p_j - c_{fuel,k} / \eta_{kl} - c_{CO2} / \eta_{kl} \cdot \varepsilon_k) \cdot q_{ijkl} \cdot h_j - \sum_{k,l} cap_{ikl} \cdot c_{OM,kl} - \sum_k I_{ik} \cdot c_{cap,k}$$

subject to (1),(2),(3),(3*) and (3**). Equation (4) also includes a price on carbon (c_{CO2}) to allow the regulator to modify the initial equilibrium so as to reduce carbon dioxide emissions (see below). This provides a direct incentive to switch to fuels with lower carbon intensity (ε_k) by reducing their relative marginal costs.

We find the optimal solution by using the Lagrangian formalism

$$(5)\ L_i = \Pi_i + \sum_{k,l} \left\{ \sum_j \left[\lambda_{ijkl} \cdot (af_k \cdot cap_{ikl} - q_{ijkl}) \right] + \mu_{ikl} \cdot (cap_{0,ikl} - D_{ikl}) \right\} + \sum_{k \in K_i^*} \nu_{ik} \cdot \left\{ \sum_l D_{ikl} - I_{ik} \right\}$$

including the shadow prices of the capacity constraint (λ_{ijkl}), the decommissioning constraint (μ_{ikl}) and the limited total capacity constraint (ν_{ik}). From (5) the Karush-Kuhn-Tucker (KKT) conditions for the long-term decision variables can be derived:

$$(6a)\ 0 \le I_{ik} \perp -c_{OM,kl} - c_{cap,k} + \sum_j \lambda_{ijkl} \cdot af_k \begin{cases} -\nu_{ik} \le 0 & \forall i,k \in K_i^*, l = 0 \\ \le 0 & otherwise \end{cases}$$

$$(6b)\ 0 \le D_{ikl} \perp c_{OM,kl} - \mu_{ikl} - \sum_j \lambda_{ijkl} \cdot af_k \begin{cases} +\nu_{ik} \le 0 & \forall i,k \in K_i^*, l = 1..4 \\ \le 0 & otherwise \end{cases}$$

For the remaining KKT conditions of the short-term decision variable, we differentiate between strategic players with market power (SPs) who take account of their influence on price and the competitive fringes (CF) which do not. This is the second relevant distinction between players we make apart from access to technologies. The KKT conditions are thus

$$\text{(6c*)}\ 0 \le q_{ijkl} \perp (p_j - \frac{P_{0j}}{Q_{0j}} \cdot q_{ijkl} - c_{fuel,k} / \eta_{kl} - c_{CO2} / \eta_{kl} \cdot \varepsilon_k) \cdot h_j - \lambda_{ijkl} \le 0 \quad \forall j,k,l;i = SPs$$

$$\text{(6c**)}\ 0 \le q_{ijkl} \perp (p_j - c_{fuel,k} / \eta_{kl} - c_{CO2} / \eta_{kl} \cdot \varepsilon_k) \cdot h_j - \lambda_{ijkl} \le 0 \quad \forall j,k,l;i = CF$$

where (6c*) applies to SPs and (6c**) applies to CF. Both equations can be interpreted in the following way: generation is increased up to the point where the electricity spread times demand period duration equals the shadow price on capacity. However, by definition SPs can exert market power, which is represented by the anticipation of the influence on price when it changes it generation away from the competitive equilibrium generation. Technically speaking this adds the derivative of (1) with respect to q_{ijkl} in (6c*); i.e. the second term. Doing so results in a price-strategic behaviour that is motivated by the SPs' scale and ownership of a large amount of capacities in the market. That is SPs can anticipate the reaction of their own generation on market prices, which through generation also influences investment behaviour.

The model is formulated as a mixed complementarity problem (MCP). It is implemented in GAMS and solved using PATH. Code is available from the authors upon request.

	Description	Unit
Indices & Sets		
I	Players	
J	Demand periods	
K	Technologies	
L	Vintages	
K_i	Technology investment options	
K_i*	Technology investment options with resource availability limitations	
Parameters Suppliers		
P_0	Inverse demand function parameter (max. WTP)	€
Q_0	Inverse demand function parameter (max. demand)	MW
h_j	Demand period duration	hr
$cap_{0,ikl}$	Initial capacity	MW
af_k	Availability factor	
$c_{cap,k}$	Capital costs (annual)	€/(MW·a)
$c_{OM,kl}$	O&M costs (annual)	€/(MW·a)
$c_{fuel,k}$	Fuel costs	€/MWh$_{th}$
η_{kl}	Thermal plant efficiency	MWh$_{el}$/ MWh$_{th}$
ε_k	Carbon intensity	t/MWh$_{th}$
Variables Suppliers		
p_j	Electricity price	€/MWh
q_{ijkl}	Generation	MW
I_{ik}	Investment	MW
D_{ikl}	Decommissioning	MW
cap_{ikl}	Total capacity	MW
λ_{ijkl}	Shadow price of capacity constraint	€/MWh
μ_{ikl}	Shadow price of decommissioning constraint	€/MW
ν_{ik}	Shadow price of resource availability constraint (lignite only)	€/MW

Parameters Regulator*		
sc_{CO2}	CO_2 costs to society	€/t
Variables Regulator*		
c_{CO2}	CO_2 costs to generators (carbon price)	€/t
E	Total emissions	t
W	Welfare	€
* See Section 4.		

Table 2.2: Model sets, indices, parameters and variables

3. Calibration & Assumptions

3.1 Demand & Supply

We refer to 2009 as the base year for calibration and assume a scenario of constant demand until 2020. To represent fluctuating demand and wind generation, we make use of time slices that are derived by grouping all hours with similar consumption levels (load) and availabilities of wind energy. Respective data was taken from the websites of the four German TSOs, and normalized for wind in order to abstract from the installed wind capacity in 2009. Figure 3.1 shows the selected intervals for partitioning and the frequency in hours of every period[3]. Moreover, for empty cells we set the frequency to one (marked by an asterisk) in order to avoid blanks in later graphical presentations. Given the absolute number of hours the resulting distortion is minimal and of no significance for the results.

load [GW] \ wind generation [%]	5	15	25	35	45	55	65	75
72.5	181	66	32	14	1*	2	1*	1*
67.5	235	246	139	43	39	47	22	1
62.5	460	351	219	92	40	52	26	6
57.5	721	559	278	129	89	49	12	5
52.5	520	534	261	155	92	67	13	8
47.5	527	460	203	117	40	26	21	4
42.5	456	437	156	43	15	11	5	1*
37.5	57	132	33	1	5	1*	1*	1*

Figure 3.1: Time slices (frequency in hours)
Source: TSOs

To determine supply in a Nash-Cournot game inverse demand functions are required, for which prices are taken from the EEX day-ahead spot market. But matching prices to demand is not straightforward because of the trading mechanism for renewable energies. Before 2009 TSOs directly procured to traders and thus circumvented the marketplace. In October 2009 though the regulation of the feed-in tariff system (EEG) changed and TSOs are now obliged to sell electricity in the intraday EEX spot market (Federico et al. 2010). However, for the better part of the year wind energy had not been traded at the EEX and thus did not contribute to market demand. Accordingly, we reconstruct market equilibria by matching prices with residual load, i.e. total load minus wind energy production at the time. Figure 3.2. shows resulting mean prices (dots) and deviations, and the linear increasing regression through all data points.

[3] Due to incomplete data overall hours only add up to 8561.

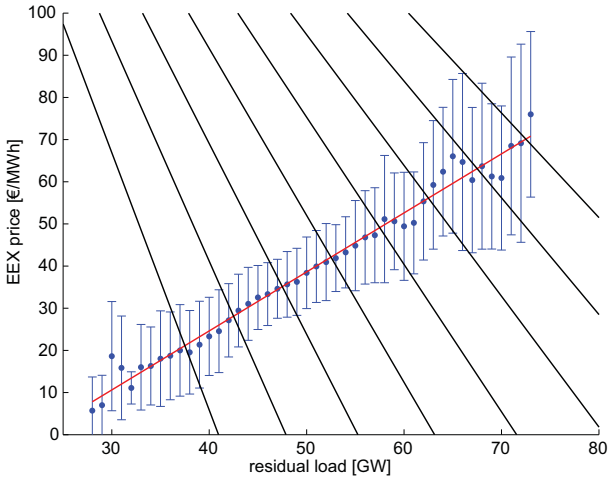

Figure 3.2: Inverse demand functions
Source: EEX, TSOs, Own calculations

For obtaining the inverse demand functions, we use the intersection of price regression and residual load as given by the partitioning of demand periods as a first anchor point; see Figure 3.2. Note that this corresponds to our modelling approach, in which all electricity is sold at the market and thus load and residual load fall together. As the second anchor point we use the maximum willingness to pay assumed at 250 €/MWh. Choosing this level is motivated by the resulting price elasticities, which range from around -0.4 for the highest to -0.1 for the lowest maximum demand. Following the argumentation by Lise & Kruseman (2008) these magnitudes seem reasonable[4], and in particular the lower levels for base load express that "it is omnipresent and cannot be moved to another time" (Pineau & Murto 2003). It should be noted that the assumption of elastic demand only holds in the long term (Weber 2005) and is thus appropriate for investment models like the one we use here. The idea behind it is that consumers may shift demand in responses to prices only over longer periods, whereas in shorter periods demand is close to being inelastic.

Regarding trade, we only consider the German sector in isolation and ignore any exchanges between connected markets with distinct structures and generation mixes. Albeit it is known that trade can have a balancing effect on prices and thereby reduce market power (Neuhoff et al. 2005), there are several reasons for a national scope. First, German imports and exports account for around 10% of total generation, and net exchanges are more or less balanced. Thus the magnitude is acceptably low, and there is no systematic bias pushing prices in one direction or the other. Second, setting the boundaries which countries to include is all but trivial. Even though there is an increasing integration of the Central European markets (EC 2010), the factual borders are hard to draw. Lise & Kruseman (2008) for example include countries such as Finland and Sweden, whereas Switzerland and Austria would have been more important to consider with respect to physical cross border flows. Accordingly, the only viable alternative would be a European market model with respectable complexity, where the focus of this analysis would be hard to maintain. Third, as an alternative import levels from adjacent markets could be represented as a function of the demand level in the domestic market like by Willems et al. (2009). However, the main argument to do so is the short term inelasticity of demand, which is valid in generation models, but not in longer term investment models (see above).

[4] The elasticities used by Lise & Kruseman are actually -0.4 and -0.8. However, their model also covers a far longer time horizon, and for shorter periods demand comes closer to being inelastic.

3.2 Technologies & Capacities

For initial capacities we refer to the databases provided by UBA (2009)[5] and BMU (2010). In total 157 conventional plants are considered: 17 nuclear (21.5 GW), 52 lignite (20.8 GW), 49 hard coal (18.3 GW), and 39 natural gas (10.6 GW). In addition, 25.8 GW of installed wind power capacity is available. According to ownership plants are assigned to the SPs (RWE, E.ON, Vattenfall, EnBW) and the CF as shown in Figure 3.3. Required thermal capacities are derived from a technology specific age-efficiency correlation established by Schröter (2004), and are averaged for every vintage. This calibration captures to the German wholesale market. We exclude combined heat and power (CHP) and peaking plants[6] (natural gas turbines and oil plants), because they do not sell under marginal cost pricing conditions and hence cannot be properly represented; for peaking plants see for example the explanations by Keppler (2010). Moreover, we also leave out hydro plants, which are mostly operated as pump storage and thus would require a setup where demand has a temporal order.

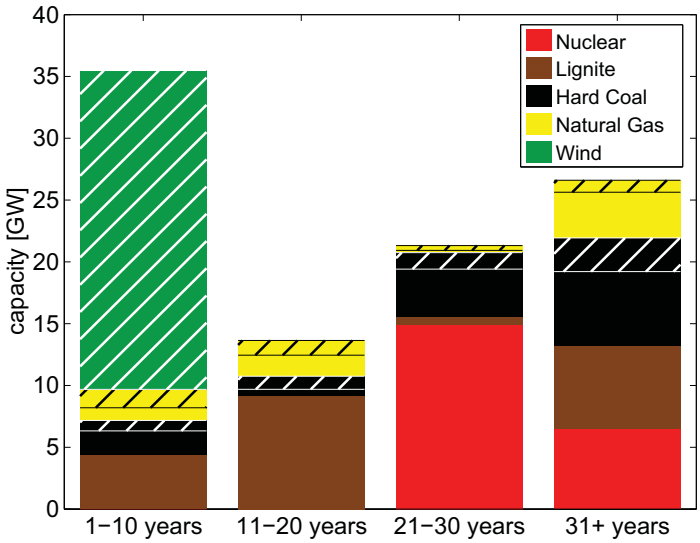

Figure 3.3: Total initial capacities (CF shares hatched)
Source: UBA (2009)*, BMU* (2010)

The initial capacities are modified by investments, and an essential feature of the model is that the competitive fringe has access to only a subset of the available technologies thereby (see Table 3.1). This is mainly motivated by financial reasons, namely base load technologies have too high up-front investment costs for smaller investors. As IEA (2010) explains, due to this and the long lead construction times incurring considerable interest during construction (IDC), "only large utilities have the financial strength to undertake such projects.". This perfectly links to the market structure as represented here, and investment activities during the last decade in Germany lend further empirical evidence (Pahle 2010). To reflect the current political situation, the construction of new nuclear plants is not possible. Moreover, due to the limitations in German lignite availability (Schiffer 2008), an additional constraint holds that the overall lignite capacity must not exceed the initial capacity, i.e. new investment must be accompanied by decommissioning of at least equal size. This reflects the situation that all mining sites are already developed with plants nearby, and thus new plants must necessarily replace old ones.

[5] Only plants >100 MW are listed.
[6] In Germany peaking plants are operated in a separate balancing market, which we do not consider here. Moreover, CHP plants only sell electricity as a by-product regardless of market conditions.

Technology	SPs	CF
Nuclear	-	-
Lignite	+	-
Hard coal	+	-
Natural Gas	+	+
Wind	+	+

Table 3.1: Players' investment options

Regarding wind, we assume that from now on the price of CO_2 is the only instrument and no further subsidies for renewables are granted. In fact, given the by now relatively low investment costs especially for wind, such an EEG opt-out in favour of purely market driven investments is currently discussed.

3.3 Costs & Technological Parameters

For cost assumptions we mainly refer to the recent survey on energy scenarios commissioned by the German government (EWI et al. 2010); missing information is supplemented by other studies. Regarding capital costs we calculate an annuity based on a fixed charge rate[7], which comprises the financial lifetime of the plant and the interest rate for capital. For the sake of simplicity we assume a 7% interest rate independent of investor and technology. Note that in contrast to technical lifetime calculations this approach defines an amortization period and derives required yearly cash flows, which better resembles investment decision making.

As for O&M, we assume costs exclusively fixed and independent of generation. This is admittedly partial, but mainly owed to the inconsistent treatment of O&M in the literature. While EWI et al. (2010) and IEA (2005) list only fixed costs, IEA (2010) merely provides variable costs. Only Konstantin (2009) describes a number of expenses potentially falling under a wider O&M category including variable and fixed parts, but it is unclear how they actually sort out. Accordingly, we restrict the model to fixed O&M costs. Moreover, we assume that these costs increase with the age of a plant. Even though respective data is sparse and in general O&M contracts are designed to equally distribute costs over the whole lifetime (Nollen 2003), we justify this by the higher risk of breakdown when components approach their age limit (Table 3.2). As mentioned earlier, O&M costs are the decisive factor regarding decommissioning of old plants in the model. Hence respective model results depend on the assumed parameters.

Technology	Financial Lifetime [a]	Cap. Costs [€/kW]	Annuity [€/kW/a]	Fixed O&M costs** [€/kW/a]	Fuel costs [€/MWh$_{th}$]	Therm. efficiency [%]	Carbon intensity [t/MWh$_{th}$]
Nuclear	-	-	-	58 (57[c] / 59[e])	8*** (9.9[b] / 7.2[d] / 6[e])	-	0
Lignite	25 (20[a] / 35[e])*	1.700 (1.850[b] / 1.700[d] / 1.500[e])	146	27[b]	4 (5[b] / 4[d] / 4[e])	45[b]	0.41[e]
Hard Coal	25 (20[a] / 35[e])	1.300 (1.300[b] / 1.450[d] / 1.200[e])	112	24[b]	10 (10[b] / 10[d] / 10[e])	46[b]	0.34[e]

[7] For FCR calculation see for example IPCC (2005) or Bodansky (2004).

Natural Gas	20 (17[a] / 25[e])	750 (950[b] / 800[d] / 530[e])	71	20[b]	25 (23[b] / 27[d] / 24[e])	60[b]	0.2[e]
Wind	20	1.030[b]	97	41[b]	-	-	0

[a]EWI & EEFA (2007)
[b]EWI et al. (2010)
[c]IEA (2005)
[d]IEA (2010)
[e]Konstantin (2009)
*All values from surveyed literature listed in brackets. Rounded and referring to the studies' base years or 2020 where available. Dollar converted to Euro using exchange rate 1.3.
**Increasing for older vintages: v1=100%, v2=100%, v3=125% and v4=150% of listed value.
***Per MWh electric.

Table 3.2: Assumptions for costs & technological parameters

4. Application & Results

The major intention of the model is to analyse the combined effects of market power and carbon pricing on investment and generation decisions. We use the German electricity sector as a case study and take the – still debated – nuclear phase out as the baseline: it decreed closure of around 22 GW of nuclear capacities within the next decade is at stake[8]. This situation has led to broad public debate, among other things about the implications regarding investments to replace nuclear capacities and the impact on targets for emission reductions; see for example EWI et al. (2010). Hence an important political issue is addressed. Apart from that, the nuclear phase out proves to be helpful for analysis because it triggers extensive investments and thus makes dominant effects more tangible.

4.1 No Regulation

We begin by investigating the nuclear phase out without taking any additional policy instrument into account, intending to better understand the model behaviour in general and set a baseline to discuss CO_2 pricing later on. Results are shown in Figures 4.1 differentiated according to separate scenarios for market power (MP) and perfect competition (PC) [9]. As for capacities, all decommissioned plants are represented as negative capacities below the zero line. Thus all positive capacities – investments included – constitute the generation structure after the investment stage. Hatched bars indicate capacities of the competitive fringe (CF), whereas non-hatched bars indicate capacities of the strategic players (SPs). With respect to prices and generation, bars indicate the overall generation in each time slice. Time slices are arranged so that vertical black lines separate groups with identical demand (y-axis in Figure 3.1). Within each group, wind energy availability (x-axis in Figure 3.1) increases from left to right. By doing so the two dimensional time slices are unfolded along a single dimension. Moreover, prices in each time slice are shown as blue dots (notice that the scale of the y-axis bears two dimensions, for capacity as well as prices).

In general, prices and quantities show several patterns common to all scenarios. First, there is a certain order with which technologies set in for generation over the various time slices. Said in conventional terms, lignite supplies base load, hard coal intermediate load, and natural gas peak load. This order corresponds to the technologies' short-run marginal costs and is typical for electricity markets. Wind is a special case having zero marginal costs, and always generates at the full availability of the time slice, which increases from left to right in each group (see above). This leads to a triangular shape, which in times of lower demand displaces conventional technologies. Second, as expected prices in general increase with higher demand. Within each group of time slices with equal demand though, prices decrease marginally due to higher wind generation that slightly raises the overall generation level. These differences between minimal and maximal generation also increase with higher demands, resulting in considerable price spans during peak demand times. At that point all conventional capacities are used up to the limit, and thus wind fluctuations cause a high variation of prices.

Two observations about technologies and prices require further attention: the relatively low usage of natural gas and the high price responsiveness to wind availability during peak load times. This mainly goes back to leaving out additional peaking capacities that in Germany are operated in a separate balancing market, which we do not consider here for technical reasons;

[8] Originally enacted in 2002, the phase out is now on the edge of being revoked by the current Government. However, it is still highly disputed and may possibly be sustained.
[9] That is equation (6c**) replaces equation (6c*) for players with market power.

compare Section 3.2. In fact these capacities, mainly gas turbines, only sell to the market at relatively high prices. Accordingly, if they were included here they would increase the share of natural gas and dampen peak prices, and the resulting model behaviour would be more in line with the standard expectation about Germany's electricity market. However, this only incurs a minor distortion to overall results because of the low share of peaking hours in total generation. More precisely, the two group of time slices with highest demand – where price responsiveness is highest – only account for around 12% of all hours in the year; compare Figure 3.1. Accordingly, profitability and thus investments are mainly determined by prices in base and intermediate load periods, for which the above described effects are relatively small.

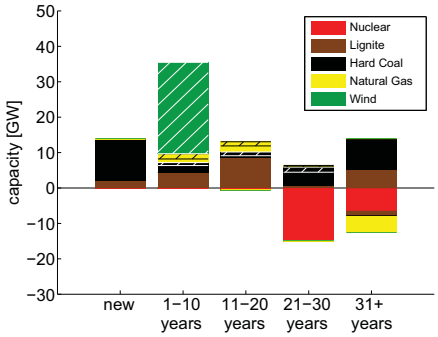

Figure 4.1a: Capacities (MP)

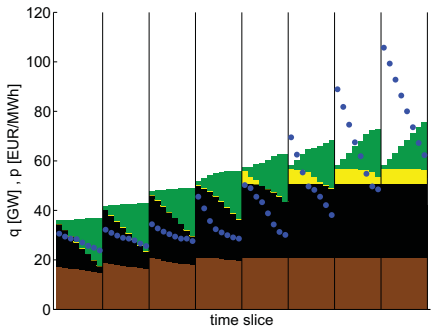

Figure 4.1b: Prices and generation (MP)

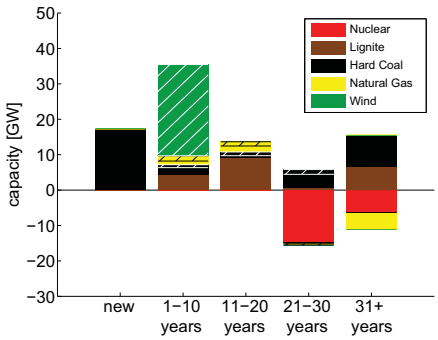

Figure 4.1c: Capacities (PC)

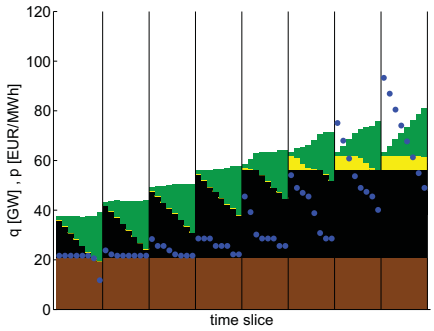

Figure 4.1d: Prices and generation (PC)

When looking at investments in more detail, three important observations stand out in the MP case (Figure 4.1a). First, only the oldest plants (31+ years) are decommissioned[10], which is what could be expected due to their economic disadvantages compared to newer plants with higher efficiency and lower O&M costs. Out of the total 6.2 GW brought offline, the major share (4.7 GW) is natural gas along with some lignite (2 GW). Second, the 13.8 GW new investments are exclusively coal, with 11.8 GW falling to hard coal and 2 GW to lignite. In the case of lignite, there is a one-to-one replacement[11] of old with new capacity by two players (RWE, Vattenfall). The case of hard coal is bit more complex and sheds some light on the particular properties of investment models of Nash-Cournot type: all MP players contribute to the new hard coal capacity with equal shares, i.e. every player adds around 2.9 GW. The reason is that both first order conditions and cost parameters are identical to all players, implying that their respective decisions are identical as well. One could have assumed that the different capacities already owned by the players would have made a

[10] Except for nuclear (red) which is decommissioned by definition.
[11] Due to the resource availability constraint (3**).

difference, but – as will become clearer below – initial endowments do not matter for investment in new capacities[12]. And finally third, total closures add up to around 28 GW, whereas investments only sum up to 13.8 GW leaving a "gap" of around 14 GW. This finding must be interpreted with caution though. Because the model formulation and calibration is partial and draws on several approximations, the assumptions about supply and demand side may not necessarily reflect an equilibrium ex-ante. Accordingly, closures may be overly high in order to properly match supply to demand. Nevertheless, as we primarily focus on the technological turnover, i.e. to which extent technologies replace each other, we can still draw relevant conclusions.

A comparison to perfect competition (PC) results reveals that – as expected – the average price is lower and total generation is higher than in the MP case: 38 €/MWh vs. 48 €/MWh, and 3.69 TWh vs. 3.52 TWh respectively (see Figures 4.1b and 4.1d). This can be traced back to building – and using – more new hard coal capacity in the PC case, and a curtailment of less efficient coal generation during times of lower demand to some extent in the MP case. In fact, investments in the perfect competitive setting are exclusively in hard coal and around 24% higher (17.2 GW); see Figure 4.1c. This result is somewhat surprising given the findings for investments under market power in the literature so far (see Section 1). Apparently, there is no pronounced tendency to oversupply either baseload (coal) or peaking (natural gas) capacity. Rather the more commonly known effect of overall output reduction in the market seems to dominate capacity expansions. Moreover, the question arises why – given that the PC scenario shows that hard coal is the only competitive and thus least cost technology – lignite is built in the MP scenario at all. One could assume that lignite provides unilateral opportunities for each player to increase his profits, and in turn remaining players react by also investing in lignite to gain relative advantage. This is a typical rent-reducing effect of non-cooperative equilibria, and was observed for example by Schill & Kemfert in the case of storage usage (2011). However, additional experiments show that when disabling lignite investments in the MP case for all except one (arbitrary) player, this player invests in lignite even though his profits decrease by doing so. This seems rather counterintuitive, but is a direct consequence of the first order conditions that hold for all technologies independently. Due to this players do not optimize their overall portfolio, and every single technology acts like an autonomous agent in the market[13]. We term this the "player's self-competition in technologies". In consequence, players compete with themselves and thereby reduce the more pronounced effect of market power that would set in if they did not to utilize this technology. This is not a part of the original decision problem though, and thus remains unacknowledged in the Nash-Cournot approach.

A final aspect concerns the role of the assumption to restrict hard coal investment to strategic players. It turns out that when all players have access to this technology in a modified MP case (MP+), investments reach the highest overall level (21.3 GW). Notably hard coal is only – and excessively – built by the competitive fringe (19.9 GW), whereas oligopolists only build 1.4 GW of lignite capacity. Concerning prices and generation, this results is identical to the PC case (38 €/MWh, 3.69 TWh), even though the ownership of capacities and technologies in the power mix differ considerably. The exclusive investments in hard coal by the competitive fringe in MP+ also requires further attention In fact, once any technology is "competitive" in the sense that it can be operated under no-profit conditions by the competitive fringe, the strategic players refrain from any investments in it at all. The reason is

[12] At least not for investments. Regarding plant closure though, the unilateral shutdown of lignite capacity indicates that players react individually to the new market conditions according to their endowments.
[13] This could correspond to a situation where players operate a separate business unit for each technology, which makes independent investments and generation decisions.

that when a competitive player operates this technology, the right-hand inequality in (6c*) must equal zero by definition. Due to the additional negative price anticipating term for SPs though, the respective right-hand term in (6c**) can never equal zero at the same time, and hence no generation occurs. Accordingly, no investments are made in this technology. We term this behaviour "SPs' competitive technology reluctance". In consequence, a certain influence of market power in investment games rests on the control of (baseload) technologies by strategic players.

4.2 CO_2 Pricing

The most important finding in absence of regulation with regard to technology choice is the exclusive use of coal for investments. Given its economic conditions this technology is without alternatives, i.e. natural gas plays no role at all. Once a carbon price is in place though, the question arises how investments levels and technology choice change in response. It goes without saying that the proper level is related to the reduction of emissions and thus investments in the cleaner technologies. Accordingly, the focus will be to investigate to which extend carbon pricing displaces coal with natural gas.

We assume exogenous carbon prices and first look at moderate level of 20€/t. Due to the additional costs of CO_2 for generation, average prices shift upwards and generation is decreased in both cases, while at the same time the difference between PC and MP is reduced: 52 €/MWh vs. 59 €/MWh, and 3.44 TWh vs. 3.33 TWh respectively (see Figures 4.2b and 4.2d). Investments in the MP case now also entail natural gas with around 3.8 GW, whereas coal is reduced to 6.6 GW (Figure 4.2a). Due to the behaviour pointed out above ("SPs' competitive technology reluctance"), natural gas is exclusively built by the competitive fringe. With respect to plant closure, there are only minor changes compared to no regulation, namely slightly more lignite and less natural gas instead. In contrast, the PC case is still dominated by hard coal (Figure 4.2c), albeit at a lower level of new investments (13.3 GW) compared to no regulation (17.2 GW). Apparently, competitive prices are still too low to provide opportunities for natural gas, despite the improved economic conditions compared to coal due to CO_2 pricing. From the perspective of technology choice, only the increased prices due to market power trigger the entry of natural gas in the market at a carbon price of 20 €/t, bringing along an additional environmental benefit from a welfare perspective (see below).

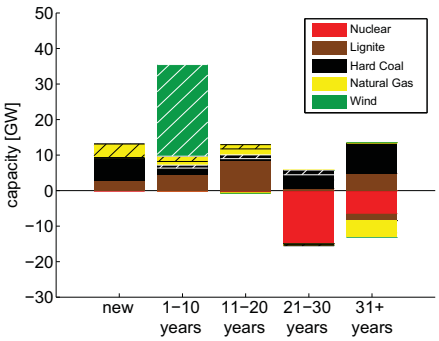

Figure 4.2a: Capacities (MP) (p_{CO2}=20€/t)

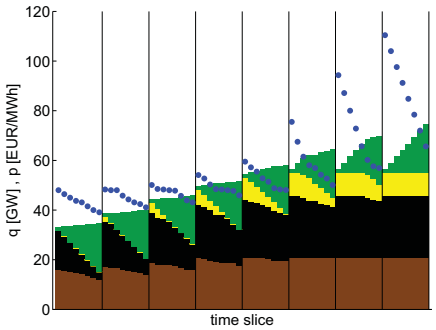

Figure 4.2b: Prices and generation (MP) (p_{CO2}=20€/t)

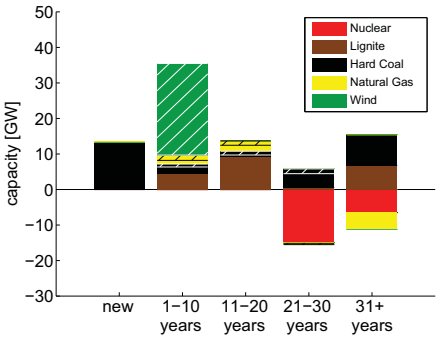

Figure 4.2c: Capacities (PC) (p_{CO2}=20€/t)

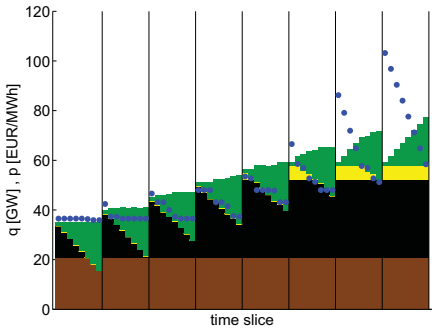

Figure 4.2d: Prices and generation (PC) (p_{CO2}=20€/t)

To complete the inspection of CO_2 pricing we take a look at 40€/t, which adds a respectable mark-up on generation costs. At this level results show an important qualitative distinction to earlier scenarios, namely the convergence of prices and generation in both the MP and the PC case to identical values: 66 €/MWh and 3.2 TWh. The main reason is that new investments are only in the "competitive technology" natural gas now. In the MP case as much as 24 GW are added, exclusively by the competitive fringe. This magnitude is also related to the more extensive closures of the oldest plants, which now also include all hard coal capacities of 31+ years (8.7 GW). In the PC case the situation is similar, but new investments accrue to only 17.3 GW[14], mainly because the major share of old lignite capacity is not decommissioned. Admittedly this is counterintuitive, as one could have assumed such a retaining rather in the MP case. However, the presence of market power again facilitates the technology turnover of the power mix, because the price awareness of strategic players provokes an over-decommissioning.

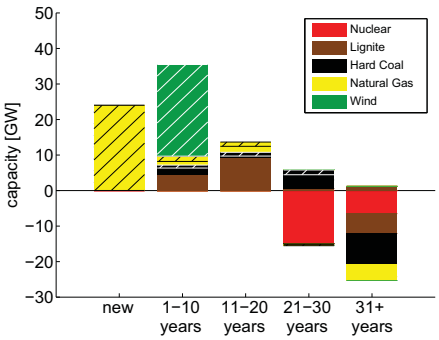

Figure 4.3a: Capacities (MP) (p_{CO2}=40€/t)

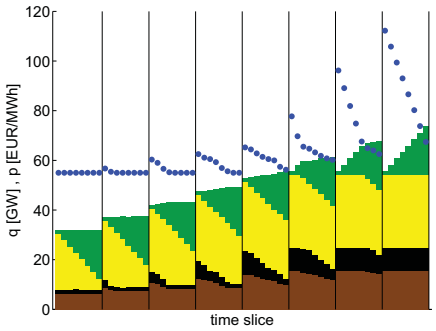

Figure 4.3b: Prices and generation (MP) (p_{CO2}=40€/t)

[14] Note that here again investment are symmetric with all players having equal shares (see above).

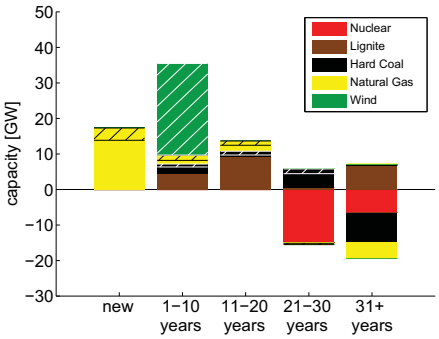

Figure 4.3c: Capacities (PC) (p_{CO2}=40€/t)

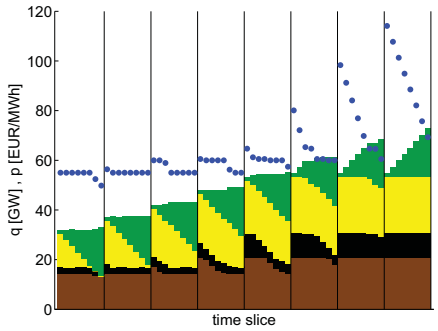

Figure 4.3d: Prices and generation (PC) (p_{CO2}=40€/t)

A final aspect unacknowledged so far concerns wind. Neither a price of 20€/t nor 40€/t induces any wind investments, even though capital and O&M costs are at a relatively moderate level (see Table 3.2). Further experiments show that a price of 132€/t is needed, regardless of the presence of market power. Similarly Reimbaud (2003), assuming a load factor of 30%, finds that a price of 116 €/t is needed to make wind competitive with natural gas. The reason is twofold: first, wind availability is in general very low (see Figure 3.1), and in the data used here only reaches a load factor of around 17%. And second, in all periods when wind availability is particularly high, prices are lowest given a certain demand (see for example Figure 4.3b). In consequence, it needs a very high carbon price to make wind more profitable than natural gas. Hence under the conditions assumed, there will be no further expansion of wind below 132€/t without additional subsidies.

4.3 Welfare Analysis & Optimal Pricing

The previous inspection of CO_2 pricing has shown how the modelled market responds in terms of adapting capacities and generation. Moreover, results suggested that a cleaner energy mix incurs a deadweight loss due to reduced generation that come along with higher prices. Thus in order to set the optimal CO_2 price level, costs and benefits must be balanced under welfare considerations. This comprises consumer and producer surpluses, revenues gained from CO_2 pricing, and the social costs of total emissions (E); see equation (8). The latter requires additional assumptions on the social costs of carbon per ton emitted (sc_{CO2}), which we analyze for a range of 10-50 €/t CO_2.

$$(7)\quad E = \sum_{i,j,k,l} q_{ijkl} / \eta_{kl} \cdot \varepsilon_k \cdot h_j$$

$$(8)\quad \begin{aligned} W = \; & \underbrace{+\sum_j (P_{0j} - p_j) \cdot \bar{q}_j / 2 \cdot h_j}_{\text{Consumer surplus}} \\ & \underbrace{+\sum_{i,j,k,l} (p_j - c_{fuel,k} / \eta_{kl} - c_{CO2} / \eta_{kl} \cdot \varepsilon_k) \cdot q_{ijkl} \cdot h_j - \sum_{i,k,l} cap_{ikl} \cdot c_{OM,kl} - \sum_{i,k} I_{ik} \cdot c_{cap,k}}_{\text{Producer surplus}} \\ & + \underbrace{E \cdot c_{CO2}}_{\substack{CO_2 \text{ pricing} \\ \text{revenue}}} - \underbrace{E \cdot sc_{CO2}}_{\substack{\text{Social costs of} \\ \text{emissions}}} \end{aligned}$$

In order to find the optimal price level, we scan the welfare space for the maximum value. More precisely, given certain social costs we solve the model for carbon prices between 0 €/t

and 60 €/t with discrete steps of 1 €/t and calculate the resulting welfare. Doing so allows us to systematically analyze the full solution space and its topographical properties, and to find the maximum welfare and the optimal price level to which it corresponds; see Figures 4.1a and 4.1b. Inspection of the curvatures shows that the global shape is convex with maximum values located at the interval's interior. This gives rise to the assumption that the chosen range of prices indeed includes the optimum for all cases. However, this argumentation is not strict in a mathematical sense, and the properties of the space and its subtleties will receive more discussion below.

As for results we first look at the perfect competitive market setting, for which economic theory dictates that the price of carbon should equal social costs, i.e. the Pigouvian level. As Table 4.1b shows, both values come very close to each other, albeit not being identical except for the 40 €/t case. The minor deviations are possibly caused by the relatively low curvature around the optimum in unison with some inaccuracies of numerical solving that create tiny "ditches" in the otherwise smooth surface. Thus model results in general confirm theory. Regarding the market power setting, the literature states that the optimal price should be below the Pigouvian level, as for example argued by Ebert (1991) using an analytical stylized model. The main reason is that lower CO_2 prices increase output and thus counteract the output decreasing effects of market power[15], which leads to higher surpluses. Needless to say that these increasing surpluses must be balanced with the also increasing damages from emissions, and in consequence account less for high social costs of carbon. In fact, both the lower carbon prices and the tendency of the difference to reduce with higher social costs are supported by Table 4.1a. Of course, we do not know if additional effects set in for even higher social costs than investigated here. The linear demand and cost structures used in our model suggest that this finding is stable, but convex costs for example may lead to different outcomes.

A closer examination of the results reveals that welfare continuously decreases when social costs of carbon rise. Moreover, CO_2 pricing creates considerable distributional impacts, especially for incumbent firms and consumers, whereas the competitive fringe remains unaffected to a large extent. Such a situation may lead governments to redistribute carbon pricing revenues to the afflicted groups, or allocate emission rights for free as incumbents are concerned. However, experience with the EU ETS has shown that the success of such a scheme crucially depends on allocation rules and if generators mark-up opportunity costs or not. In Germany for example this has lead to considerable investment distortions in disadvantage of cleaner technologies (Pahle et al. 2011). A second observation is related to the difference between the PC and MP cases: relative welfare losses range from 0.75% (10 €/t) to 0.25% (50 €/t). These magnitudes are relatively moderate and underline that even though technology choice can vary considerably, different market structures hardly matter under welfare considerations. The reasons are basically twofold: for low social costs of carbon, producer surpluses for strategic players are relatively high because they can extensively use existing capacities. This happens at the expense of the consumer surplus and also the incurred emissions, which are only partially balanced by carbon pricing revenues. Nevertheless, gains and losses roughly compensate on the whole. For higher social costs, strategic players gradually lose influence because their capacities are crowded out by the competitive fringe. That is, the market becomes more and more competitive by which the initial differences dissolve.

[15] Traber & Kemfert (2011b) investigate another measure, namely the redistribution of CO_2 pricing revenues as subsidies on production. However, the do not consider optimal price levels for doing so.

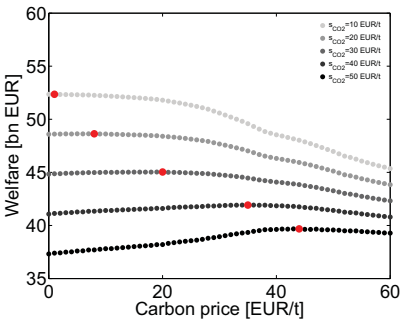

Figure 4.4a: Welfare space (MP)

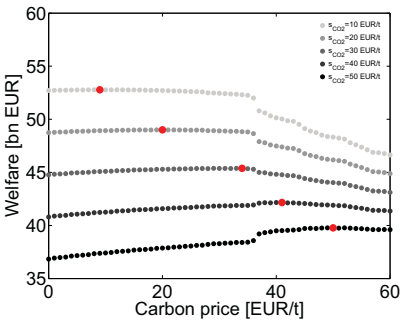

Figure 4.4b: Welfare space (PC)

Social Costs of Carbon [EUR/t]	Opt. Price of Carbon [EUR/t]	Prod. Surplus MPs [bn EUR]	Prod. Surplus CF [bn EUR]	Consumer Surplus [bn EUR]	Emissions [Mt]	Carb. Pricing Revenues [bn EUR]	Social Costs of Emissions [bn EUR]	Welfare [bn EUR]
10	0	8,4	1,6	46,1	376	0,0	3,8	52,4
20	7	7,6	1,7	44,1	365	2,6	7,3	48,6
30	19	5,6	1,8	41,4	342	6,5	10,3	45,0
40	34	2,5	1,6	39,3	263	9,0	10,5	41,9
50	43	1,4	1,6	38,1	212	9,1	10,6	39,7

Table 4.1a: Optimal price level and welfare parameters (MP)

Social Costs of Carbon [EUR/t]	Opt. Price of Carbon [EUR/t]	Prod. Surplus MPs [bn EUR]	Prod. Surplus CF [bn EUR]	Consumer Surplus [bn EUR]	Emissions [Mt]	Carb. Pricing Revenues [bn EUR]	Social Costs of Emissions [bn EUR]	Welfare [bn EUR]
10	8	4,6	0,9	48,1	386	3,1	3,9	52,8
20	19	3,8	1,2	44,4	372	7,1	7,4	49,0
30	33	2,8	1,5	40,0	349	11,5	10,5	45,4
40	40	2,1	1,6	38,5	266	10,7	10,6	42,2
50	49	1,1	1,6	37,2	215	10,6	10,8	39,8

Table 4.1b: Optimal price level and welfare parameters (PC)

Furthermore, looking at losses in case of non-optimal pricing, there is only a relevant impact for large deviations from the optimum; see Figures 4.1a and 4.1b. In its vicinity deviations from the optimal price level are relatively flat and only induce minor welfare reductions. Moving further away can provoke considerable losses though – for example in the case of 10 €/t social costs and prices higher than 50 €/t – leading to a 20% decrease and more. An eye-catching feature in that regard is the discontinuity in the perfect competition setting (PC) that occurs between a carbon price of 36 €/t and 37 €/t. It turns out that at this point hard coal and natural gas reach equal marginal costs of around 54 €/MWh, and investments change from nearly exclusively hard coal (36 €/t) to natural gas only (37 €/t). This somewhat awkward behaviour, also known as penny-switching, only occurs when all players are competitive. When market power prevails, the shift in technologies happens more gradually and only exhibits a small kink at the respective point. As for the cause of the different behaviours we conjecture the following: in the market power setting, strategic players raise prices above competitive levels, which at some point allows the competitive players to add new natural gas capacity, even if coal is still the cheaper option. With increasing carbon prices, the cost advantage of coal becomes smaller and it gets more and more displaced. Hence the switch from one technology to the other is smoother. By contrast, a perfect competitive market only chooses the cheapest technology in the described the-winner-takes-it-all style.

A final remark must be made about finding the optimal instrument level in the above way by scanning the overall welfare space for given social costs. Even though this approach has served our analysis well, it may lack some sophistication. In that sense a probably more elegant way is the formulation as a single mathematical problem with equilibrium constraints (MPEC), for which dedicated solvers in GAMS are available. Solving the MPEC may deliver the optimal solution of the corresponding hierarchical game straight away, albeit it is known that algorithms are to some parts still in development stage (Gabriel & Leuthold 2010). To check applicability we reformulated the model accordingly, but eventually failed to reproduce the optimal price levels as listed in Tables 4.1a and 4.1b. We conjecture that this was due to the local non-smoothness and only partial convexity of the solution space. Thus from our point of view scanning the full space remains the method of choice, especially when the space's dimensionality is sufficiently low.

5. Discussion & Conclusion

In this paper we have analyzed technology choice and optimal carbon pricing related to investments in electricity markets with imperfect competition. A first important finding concerns the more general behaviour of the Nash-Cournot approach including investments, which we have made use of. Even though respective models are widely employed, they show some important characteristics that have largely been unacknowledged in the literature so far. First, once a technology is competitive and available to non-strategic players as an investment options, strategic players refrain from investing in it all ("SPs' competitive technology reluctance"). Second, because of the particular formulation of the problem and the resulting model structure all players optimize investments and generation of all technologies independently. This leads to the situation where (strategic) players invest in technologies, even though they decrease their profits by doing so ("player's self-competition in technologies"). Admittedly, this behaviour is somewhat artificial and different from what one would expect in a real market, where truly strategic players should make a joint optimization of their overall portfolio. However, this is beyond the scope of Nash-Cournot models. The only approach so far that could, at least in theory, properly represent portfolio optimization is the supply function equilibrium (SFE); compare Ventosa et al. (2005). In SFE models, players decide about quantities and prices simultaneously, and are thus fully aware of their overall supply structure. However, such models are still sparsely used and poorly understood. Moreover, they have major drawbacks: "they are difficult to calculate, often have multiple equilibria, often give unstable solutions and require strong simplifications with respect to market and cost structures." Willems et al. (2009). To our knowledge no SFE model with integrated investments exists so far[16], and it probably needs years of further research until such a model becomes available for application. For the time being, Nash-Cournot models will likely remain the method of choice despite their limitations. Understanding their limitations therefore seems fundamental.

A second important finding concerns technology choice under carbon pricing. Higher prices decrease the relative competitive advantage of coal compared to natural gas due to its higher carbon intensity. Both technologies reach an equal level of short-term marginal costs between 36 €/t and 37 €/t, and if the market is perfectly competitive investments fully switch from hard coal to natural gas. When market power prevails though, the shift in technologies is more gradually, and the higher prices open up opportunities for natural gas even below the turning point of 36 €/t. Moreover, once natural gas is the only competitive technology at 37€/t or higher, the SPs' requirements to operate capacities only under rent-generating conditions triggers a more extensive closure of old lignite capacities than under perfect competition. Thus market power, at least as modelled here, facilitates the technology turnover towards a lower carbon-intensive power mix. Furthermore, bringing wind into the market requires CO_2 prices higher than 131€/t in the model – independent of market power. Clearly, as a long as real-world CO_2 prices remain in the order of 20€/t, the market alone does not provide sufficient investment incentives and therefore additional support schemes are needed. However, the barriers for wind are not only related to costs, but also to price effects in markets based on the marginal pricing principle. More precisely, if prices are set by short run marginal costs, too much wind in the power mix reduces overall prices, and capital costs cannot be recovered. Thus the higher the share of wind in generation, the lower the incentives for new investments. In face of ambitious targets for renewables, new design schemes for electricity markets are needed which are able to provide appropriate incentives; compare Newberry (2010).

[16] Following an earlier idea to use SFE for this analysis, one of the authors of Willems et al. (2009) strongly discouraged us to do so because of the numerical difficulties.

Finally, from a welfare perspective we find that losses due to market power compared to perfect competition are relatively moderate and never exceed 1%. Even when coal technologies can exclusively be invested in by strategic players, this matters very little in the end. In the case of low social costs of carbon, higher SP producer surplus compensates lower consumer surplus and the social costs of emissions. For higher social costs and thus higher prices of carbon, new investments are exclusively in natural gas making the market increasingly competitive. Accordingly, welfare losses diminish. However, distributional impacts are considerable, and especially strategic players incur considerable losses compared to a situation without regulation. Thus political economy could be an important barrier for implementing high prices, especially if market power indeed exists.

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Chapter 5

Synthesis, Discussion & Further Research

The main theme of this thesis has been how the liberalization of electricity markets and the need to reduce carbon intensity of power generation interact in Germany. Given the present situation characterized by high carbon intensity of the German power generation mix and the envisaged transformation being at a rather initial stage, investments in new capacities and respective technology choices are crucial. Because of the long infrastructure lifetimes, investments today determine the future energy system and thus indicate progress in accomplishing the low carbon transition.

A straightforward starting point is to inspect and analyze current investment trends. Germany provides a relevant case study as several challenges arise that potentially pertain other power markets in the world. On one side, ambitious emission reduction targets and policies are in place, and renewables have experienced unparalleled deployment during the last decade. However, this expansion has not been market driven, and thus only constitutes a side aspect of the overall research question. On the other side, a considerable number of new coal power plants are currently in construction, probably reflecting a worldwide renaissance of coal. This development has raised many doubts about the capabilities of pure market based approaches to induce the low-carbon transition. While a price on carbon is already implemented via the EU ETS, its so far apparent long-term "non-effectiveness" in terms of failing to stop investment into fossil-based power generation capacity has stimulated a broad public discussion. The public seems to be at odds with the ongoing "dash for coal", which can probably best be summarized with "How come we are still building coal-fired power plants in the 21st century ?"[1].

This chapter starts with a methodological overview in Section 5.1, which aims to further qualify the scientific contributions in taking account and classifying the used methods. Against this background, the synthesis of the findings of Chapters 2- 4 are presented in Section 5.2, structured along the three detailed research questions posed in Chapter 1. Finally, ideas for further research are outlined in Section 5.3.

[1] Quoted from an email I received from a GDF Suez engineer regarding the article about the drivers and factors of the dash for coal (Chapter 2).

5.1 Review & Discussion of Methods

In order to put the findings of this thesis in perspective for a comprehensive synthesis, this section reviews and discusses the different methods used in the various chapters. The second chapter empirically analyzed investment decisions, and opted for a qualitative analysis of investment drivers and decision factors. The third chapter computed expected profitabilities of investments under different allocation schemes for emission certificates using a single investor model. And the fourth chapter employed a quantitative equilibrium market model to investigate technology choice and optimal carbon pricing. All methods have their advantages and disadvantages, and they all contribute in answering the research questions in a different way, as will be pointed out in the following. From that some methodical lessons regarding the overall investigation of investments in electricity markets can be brawn, that are presented at the end of this section.

5.1.1 Qualitative Scoping of Investment Drivers & Decision Factors

A central problem for investigating investments in liberalized electricity markets is the lack of an integrated theory. That is, there is no coherent framework capable of integrating the influences of socio-political, technological and economic environments, which would give a concise distinction of drivers, decisions factors and associated risks and options. Only the model proposed by Laurikka (2006) comes close to such a framework, but is limited to the effects of climate policy and remains far from exhaustive. This shortcoming is also acknowledged in the literature. Murphy & Smeers (2005) point out that the main drivers of investment in restructured markets are still unknown. Platts (2008) remarks that it has become increasingly difficult to establish the boundaries of investment cycles, the traditional drivers that occurred out of the need to replace older plants and meet load. All in all, a multitude of potential drivers and decision factors exist, which need to be structured and put in relation to observed investments trends.

A suited approach for doing so is *hierarchy analysis,* which is helpful for identifying possible causes of an observed effect; see for example Dunn (2009). However, causes can only be classified as plausible, expressing the untested qualitative relationship to the effect under scrutiny. Nevertheless, due to the complex nature of most real-world phenomena hierarchy analysis is probably without alternative when aiming at a big picture view. Several rules need to be observed in a well-conducted hierarchy analysis: substantive relevance, exhaustiveness, disjointness, consistency, and hierarchical distinctiveness (Dunn 2009).

Figure 5.1 shows the classification scheme used for the hierarchy analysis of investment and technology choice in Chapter 2. A first group of factors is related to the electricity market, and comprises costs, prices, demand and supply. Correspondingly, these are the typical quantities included in market models (see below). But even though the market is generally seen as the decisive mechanism that triggers investment and determines technology choice, there are several important factors that are unacknowledged in these

models. These are (i) other economic factors, (ii) technological factors and (iii) socio-political factors as shown below.

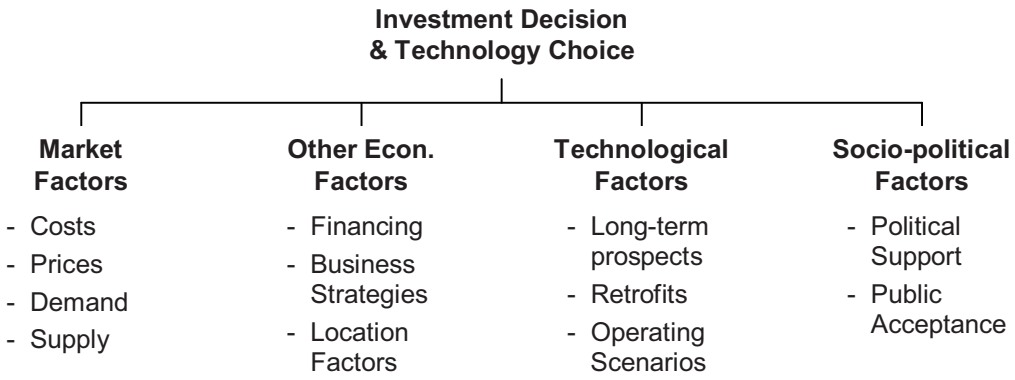

Figure 5.1: Classification scheme of investment decisions and technology choice

Of course, the relevance of these factors is certainly depends on the studied case, but as Chapter 2 shows for the German "dash for coal" they can be relatively influential. Another study adopting a similar approach is provided by Winskel (2002) in his analysis of the "dash for gas" in the British electricity industry during the 1990s. According to the author it can be understood as "[an] outcome of the interplay of previously excluded international forces with latent local interests, mediated by policymaking expediency […] rather than as a result of technical and economic imperatives, or structural and regulatory reform." Such a view arguably underrates market influences, but it provides a broad perspective that makes aware of the many other forces also at work.

5.1.2 Quantitative Market Models

Notwithstanding the usefulness of hierarchical analysis, it lacks the capability to quantify the magnitude of investment drivers, i.e. to which extent factors are actually influential[2]. Conceptually, quantitative models allow the analysis of counterfactuals within controlled experiments to investigate system reaction to changes in single parameters. This is applicable in particular to market factors, which according to standard economic theory are the major determinants of investments. Ventosa et al. (2005) provides a survey of recent electricity market modeling trends, and characterizes and classifies the various approaches that can be found in the literature. Based on the proposed classification the types of models apt for investments will be discussed in the following.

A first group are the so called *single-firm optimization models*, which focus on the actions of a single firm. The main mechanism creating the link to the market is the price clearing process, which represents the price either as exogenous variable or a function of the demand supplied by the firm. In the former case the firm acts as price taker, which implies that the firm's capacity is small compared to the overall market. But if applied to investments, such models face the conceptual difficulty that assumed prices do not evolve

[2] For example consider the role of the nuclear phase out for the "dash for coal": the case study argues that this might have been an important cause. However, it cannot quantify the actual economic incentives that arose for building new coal plants and thus should be complemented by model analysis to quantify effects.

endogenously over the planning period. Even though certain workarounds exist like using different price scenarios based on overall capacity expansions and future fuel price developments, this remains a crucial shortcoming that can only be addressed with equilibrium models (see below). However, single firm models also have their benefits. First, their analytical tractability is higher compared to full market models. In fact, they often break down to simulation models if technical constraints are not taken into account. The most prominent application in that regard is the *discounted cash flow* (DCF) approach[3], that was used in Chapter 3 and also for example in Laurikka & Koljonen (2006). Rather than optimizing investments, DCF is used to evaluate certain preset investment options by their overall performance in the market according to the net present value (NPV) criteria. Second, DCF probably best resembles the actual investment decision of an investor in face of the limited information about the market and its future development. For example it is prominently featured in a primer of energy risk management for the utility industry by Hyman (2006). Hence with a focus on a single (small) price-taking investor and an isolated investment decision and the respective choice of technology, DCF is usually the method of choice.

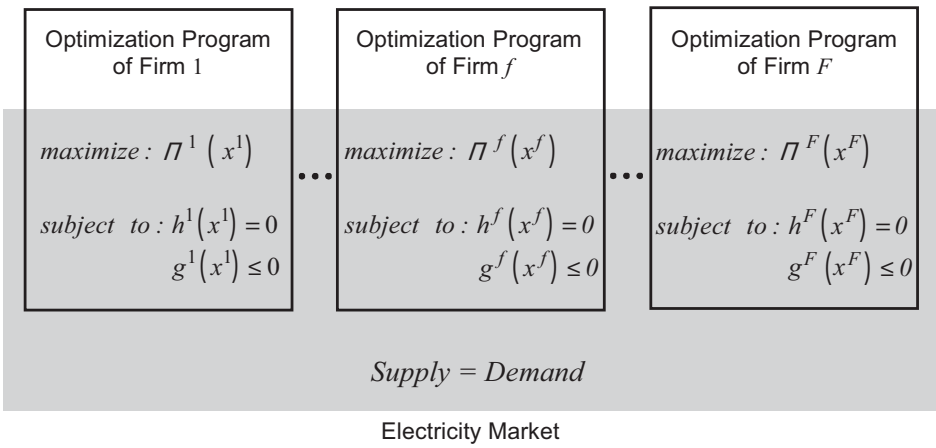

Figure 5.2: Equilibrium models (Source: Ventosa et al. 2005)

A second group are *equilibrium models*; such a model was used in Chapter 4. Their main advantage compared to single firm models is that they determine the overall market optimum, i.e. an equilibrium where every player acts optimal given the decisions of all other players; see Figure 5.2. From an economic point of view the equilibrium represents the complete description of the market and its interactions, and is thus highly desirable. It implies that all relevant decisions are endogenously determined, comprising both short-term (prices, generation)[4] and long-term (investments) variables. When choosing the problem formulation and equilibrium, an important distinction occurs regarding the degree of competition. For perfect competition, microeconomic theory proves that such a market can be represented as a cost minimization or net benefit maximization problem,

[3] Another approach are *real options* (RO), which explicitly rely on the stochasticity of exogenous parameters like electricity, fuel or certificate prices. However, RO is mostly applied with a focus of potential postponement of investment when some uncertainties resolve during the planning period; see for example Patiño-Echeverri et al. (2009).

[4] Depending on the type of competition and equilibrium.

and optimization-based models are usually the best way to do so (Ventosa et al. 2005). For imperfect competition and oligopolies though, the approach depends on the chosen equilibrium: (a) Bertrand equilibrium with competition in prices, (b) Cournot equilibrium with competition in quantities, or (c) supply function equilibrium (SFE) with competition in both quantities and prices. From the three available equilibria two can be ruled out for application due to practical reasons though; see Willems et al. (2009). Bertrand models have great difficulties in presenting capacity constraints, by which they are in general inappropriate for electricity markets. SFE models also have major drawbacks, namely they are hard to solve, often have multiple equilibria, often give unstable solutions and require strong simplifications with respect to market and cost structures. Hence in practice Cournot models are preferred for modeling oligopolistic electricity markets; see for example Chapter 4 and Oliveira (2008). Moreover, they can easily be extended to include investments rendering them useful for application in this thesis.

Yet Cournot equilibrium models have their drawbacks. Due to the underlying competition in quantities they require an exogenous inverse demand function that maps overall supply (generation) to the market price. Because first order conditions include the derivative of this function which implicitly contains demand, it has to be differentiable and thus demand cannot be fixed[5]. The implied price elasticity has two important consequences. First, it allows oligopolists to reduce generation and thereby increase prices above marginal costs, which is the very mechanism of market power. Second, it allows the last generating unit in the market to recover its long-term operation costs including the costs of capital. This is an important precondition for investment models, which by definition expand capacity only as long as it is profitable. However, in turn this also creates a flexibility to "under-supply" and thus overly raises prices given the original state of the market – crucially depending on the price elasticity. This is probably the main drawback of Cournot models, and for short-term analyses with given capacities requires additional fixes like advance contracting to match empirical market prices (Willems et al. 2009). For long-term analysis focusing on investments this problem is less severe, because price elasticities in the market can more easily be justified in the long-run (Pineau & Murto 2003).

However, Chapter 4 has shown that Cournot models have some additional peculiarities when applied to investments. First, if technologies are available for investment to strategic and competitive players alike, they are not invested in by strategic players due to the built-in profit requirement ("SPs' competitive technology reluctance"). Second, the resulting model structure describes a situation where all players optimize investments and generation of all technologies independently. Due to this (strategic) players invest in technologies, even though their profits are reduced by doing so ("player's self-competition in technologies"). This corresponds to a situation where a single firm organizes all technologies in separate business units that do not cooperate with each other. Accordingly, there is no optimization of an overall portfolio, and the effects of market power on investments remain limited. It would require an SFE model to properly

[5] Demand must equal supply at all times. A fixed demand would thus require an inverse demand function that is a straight vertical line – which is neither differentiable nor a function at all.

represent strategic capacity expansions, but as long as the related drawbacks are unresolved (see above), the Nash-Cournot approach is without alternative.

In summary, market investment models come in several flavors, and the choice of any one is essentially a matter of the research question. For a detailed inspection of the profitability of a single investment under different market and regulatory conditions like in Chapter 3, a single investor model based on the DCF approach serves best. It allows a detailed quantification of expected cash flows, and thus makes decision considerations explicit. This is less important when looking on the overall evolution of market, for example when investigating the impact of a regulatory instrument on the overall power mix like in Chapter 4. In such cases equilibrium models should be used, for which the important framework of welfare analysis is applicable

5.1.3 Methodical Lessons

The scientific analysis of investments in electricity markets still represents a considerable challenge. Many different drivers and decision factors exist, and it is still largely unresolved what eventually determines a certain decision by a certain investors. Against this background, the most promising approach is to investigate investments from different theoretical perspectives and methodological approaches. The main advantage of a quantitative scoping is that it helps to identify all plausible drivers and decision factors by explicitly considering a wide range of domains apart from the market. The main advantage of quantitative market models lies in the concise analysis of market interactions and the systematic investigation of counterfactuals. Accordingly, whereas qualitative analysis is broad but explorative, quantitative analysis is focused but causal and evaluative. The reasons to combine both approaches are apparent: Qualitative case studies can guide modeling, whereas model results can quantify effects and qualify insights of qualitative findings. Moreover, the validity of findings increases if both approaches arrive at similar results, i.e. findings are consistent[6]. This thesis comprises both approaches in order to provide an analysis as comprehensive as possible.

[6] In the social sciences this is also known as “triangulation”.

5.2 Synthesis

As pointed out in the previous section, a first and important step in investigating investments is structuring and analyzing the multitude of potential drivers and decision factors using hierarchy analysis. This corresponds to the first research question of this thesis, addressed in Chapter 2:

1. **In face of ambitious climate policy and respective instruments implemented: why are there so many new coal plants currently under construction in Germany?**

The following main reasons for the recent German "dash for coal" have been identified: (1) Replacement requirements due to the nuclear phase out and limitations due to associated location restrictions. Even though low-cost lignite would have been the preferred option, mining restrictions have lead to higher investments in hard coal. (2) Onset of a new investment cycle in the power market, following the power price increase after 2000 and influenced by the aging existing generation structure. (3) Favorable economic and technological prospects for coal compared with natural gas in the long run. (4) A status-quo bias of investors in regard to future renewable deployment. (5) Explicit political support for coal, including technology specific free allocations of EU ETS certificates to new plants. (6) Ineffectiveness of public protest in hampering new projects.

While some of these factor are not primarily market related, like for example the location factors or the explicit political support for coal in political strategies, the majority is. Further economic analysis to quantify particularly relevant effects and investigate underlying mechanisms more closely was conducted following upon this scoping study. The first was to study free allocation of EU ETS certificates, which has been widely criticized for its impacts, albeit not backed by thorough analysis on how it actually distorted investments. This scientific gap has been addressed with the following research question in Chapter 3.

2. **To which extent have national allocation rules (NAPs) of the EU ETS contributed to the failure to induce cleaner investments in Germany?**

In order to answer this question, the discounted cash flow (DCF) method was used to simulate a single investor's investment decision and technology choice. It is based on a numerical model that integrates both Germany's particular allocation rules and its specific power generation structure. Results indicate that technology specific new entrant provisions have substantially increased incentives to invest in hard coal plants compared to natural gas at the time of the ETS onset. Expected windfall profits relative to no regulation compensated more than half of the total capital costs of a hard coal plant. Moreover, shorter periods of free allocations would not have turned investors' favours towards the cleaner natural gas technology because of pre-existing economic advantages for coal. In contrast, counterfactual full auctioning or a single best available technology benchmark would have made natural gas the predominant technology of choice.

These findings confirm that EU ETS allocations played an important role as suggested by the hierarchical analysis on more qualitative grounds. Besides they make clear that details matter in implementing instruments. Even though it is still speculated if policy makers had anticipated the mark-up of carbon costs responsible for windfall profits, the outcome, i.e. the coal investments that materialized, suggests that policy making is not an idealized process with stringent predefined goals, but susceptible to vested interests[7]. As such, the "dash for coal" was also driven by political decisions.

Notwithstanding the preference for coal compared to natural gas due to allocations from a single investor's perspective, the actual decision is more complex and requires a full market perspective. Only a market equilibrium model enables understanding of the full interactions at work, and has been addressed with the following research question in Chapter 4:

3. **How can the "dash for coal" be explained from a full market perspective? More generally, how do imperfectly competitive markets affect technology choice and optimal carbon pricing?**

Addressing this question includes an important aspect identified in the qualitative scoping analysis in Chapter 2, namely that coal plants have only been built by incumbent firms, whereas natural gas and renewables – especially wind – were invested in mainly by smaller investors like municipal utilities. Furthermore, given the high concentration in the German market, incumbent firms may exert market power, whereas municipal utilities and other smaller generators are assumed to be competitive due to their size. On that ground a certain techno-economic borderline can be constituted that complements the overall research question. Does the combination of market power and exclusive access to coal, named technological market power here, leads to a particular barrier for investments in low-carbon technologies? For analysis a numerical game-theoretic investment model was used.

Baseline results without carbon pricing show that even disregarding market power and exclusive technology access, coal is the technology of choice to replace decommissioned nuclear plants. The intuition is that the supply gap due to the nuclear phase out is best filled with capacities possessing similar techno-economic characteristics. With carbon pricing though, there is much less investment to coal and gas becomes the technology of choice. The share of coal in the power generation mix is consequently gradually displaced by natural gas, and coal investments are fully displaced at a price of around 40€/t upwards. This shows that carbon pricing can be an effective instrument to drive the decarbonisation of the power sector, but only under the condition of a strict implementation that does not grant free allocations to new plants (see above). Concerning wind, investments only occur when the carbon price exceeds 132 €/t, which is currently far beyond the values expected for the coming decade; in a survey by Point Carbon (2009) only around 3% of the participants expected prices in 2020 to be higher than 100 €/t. Hence the important conclusion can be drawn that a market-based mechanism like

[7] This should be understood in a descriptive, not a normative way. Taking account of vested interest may have societal advantages, regardless of the implied distributional impacts.

carbon pricing alone provides insufficient investment incentives for renewables and additional support schemes would be needed to spur such investments.

Furthermore, bringing cleaner technologies into the market should not be the ultimate rationale of the policy maker per se, and thus a second aspect is the optimal choice of the carbon price in the context of welfare analysis. In this regard results confirm theory, namely that the carbon price should equal the marginal costs of carbon in the case of a perfect competitive market, and should be lower when market power prevails. Still, welfare losses incurred by market power are remarkably moderate and never exceed 1%. In any case, from a welfare point of view setting the price of carbon is essentially a matter of how emission reductions are valued by society, and not a means to reach a certain technological end. Hence investments in coal not necessarily work against the low-carbon transition, at least if emission reductions are not valued high enough.

In summary, the main findings of this thesis are:

- Investments in liberalized electricity markets can be caused and influenced by many factors. Market signals play an important role, but are accompanied by other factors that can prove relevant depending on the particular case. A more comprehensive integrated theory is needed in the future.
- The implementation of a price on CO_2 by means of the EU ETS was intended to incentivize a less carbon intensive power mix, in particular with respect to dynamic efficiency and investments. However, the national allocation plan (NAP) in Germany created considerable distortion by technology-specific provision of free certificates. The opportunity costs of these certificates where passed through and incurred considerable windfall profits and misallocation of investments in terms of a bias in favour of coal compared to natural gas. The German NAP probably did not cause the "dash for coal" in the first place, but substantially spurred and sustained it at least from the perspective of single investments.
- When taking market effects into account by including interactions between investors, technologies and existing capacities, this picture doesn't change much if no carbon pricing is in place. If a carbon price is set and relatively low, coal remains the preferred technology. Carbon pricing affects investment decisions only from a level of 20 €/t upwards, gradually displacing coal with natural gas as it increases. At around 40 €/t, investments are exclusively into natural gas capacity.
- The main effect of a carbon price is to push coal out of the market. However, renewables do not become competitive at carbon prices below 130 €/t. Given the current political situation such magnitudes seem extremely unrealistic, at least for the coming decade. Hence, if the need for action and an early transition is great, additional instruments for a push of renewable technologies are necessary.
- From a welfare point of view, welfare losses due to market power compared to perfect competition in Germany are relatively small and never exceed 1%. This probably goes back to the shortcomings of the Nash-Cournot to properly represent market power in investments games (see Section 5.1.2).

5.3 Further Research

This thesis has analyzed investment decisions in liberalized electricity markets under climate policy constraints in a German case study. Some answers to timely and relevant questions could be derived, but at the several others had to be ignored. This last section provides an outlook on some of them to inspire future research.

One general direction concerns qualitative analysis of the field. Hierarchical analysis in the way it was conducted here it didn't include first hand data from investors. But this may turn out be helpful in gaining insights about how investments are actually made on the company level. Some issues have already been dealt with in empirical surveys: for Germany Hoffmann (2007) investigates the EU ETS and investment decisions, and Rogge & Hoffmann (2010) and Rogge et al. (2011) the impact of the EU ETS on innovations in the power sector. However, as Chapter 2 has shown the explicit focus on the EU ETS is probably too narrow; evidence suggests that there are several other influences at work, which may overshadow the EU ETS. Accordingly, a more appropriate approach is to trace back outcomes instead. More precisely, given a particular investment decision, what have been the reasons and decision factors on the company level leading to a specific outcome. A very interesting case in this respect would be a study of Vattenfall's new coal plant in Hamburg and the originally planned coal plant in Berlin that was abandoned and replaced by natural gas and biomass; see Chapter 2. Notwithstanding possible difficulties to acquire insightful data, such a study could illustrate under which circumstances investors uphold or revise their plans. Another issue for which more scientific analysis is highly desirable is the difficulty of finding new sites which foreign firms planning to enter the German market experienced (Brunekreeft & Bauknecht 2006). Grid accessibility and capacity may have played a role in this, and so have location factors or problems with public acceptance. In any case, concerning the future development of the market structure and more competition such a study would be highly relevant.

Apart from more empirical work, the model developed in Chapter 4 may serve well for further applications; one such area is that of information and uncertainty. Oliveira (2008) has made an important point in highlighting the crucial role of information and expectations in electricity investment games. In particular this concerns the conjectures each single player has about the underlying information sets and thus the actions of all other players. For example consider a player who assumes CCS for coal to be available and profitable in the near future. If in one case he conjectures that his competitors maintain the same assumption, he will probably build less new capacity of this technology, as he anticipates a market equilibrium where all other players invest alike. If, however, in a second case he conjectures that his competitors maintain a different and more skeptical assumption, he might built more new capacity of this technology considering himself as the only investor[8]. The work by Oliveira (2008) shows that when investment games are extended with asymmetric information, they become much more complex and to some extent also hard to ground in empirical data. Nevertheless, they probably much better resemble the outcome of such games in real markets. At the least,

[8] This may also make him reconsidering his assumptions about CCS, but that is another story.

they may help to investigate if asymmetric information may distort the long-term efficiency usually attributed to liberalized markets (see Chapter 1). Similarly, risk and uncertainty may work in the same direction in the context of investments. Even though a lot of work on this issue already exists on the level of single investor models (see Chapter 3), especially based on the real options approach, its impact in equilibrium models has sparsely been analyzed so far[9].

A second area calling for more research is that of market design and potential curtailment of intermittent renewable energy generation. High shares of wind in the power mix lead to a considerable reduction of prices when the market price is based on short-run marginal costs (Newberry (2010). Consequently, investment in new plants becomes less profitable, and the market could reach a deadlock where no new capacity is added. Thus even though the question of market design is not primarily related to investments, its most important implications occur when planning new capacity. The analysis in Chapter 4 considered only a market-based expansion of wind, and renewables (wind) only entered the market at very high and currently unrealistic carbon prices. If the current feed-in tariff (EEG) continues though, generation by renewables will be considerably higher in the next years. Under such conditions a redesign of the market is very likely unavoidable, and thus an ex-ante analysis is advisable. However, it is probably useful to use a detailed dispatch model in complementation to properly represent temporal details and hour-wise fluctuations, which get lost when aggregating to time slices. This puts a special value on the flexibility of technologies, which is widely considered important, but can only be valued if short-term deviations are taken into account.

[9] Fan et al. (2010) deal with risk aversity and investments. The underlying market model is highly stylized though.

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Statement of Contribution

The three core chapters of this thesis are the result of collaborations between the author of this thesis and his advisor, Prof. Dr. Ottmar Edenhofer, sometimes involving additional colleagues as indicated. The author of this thesis has made extensive contributions to the contents of all three papers, from conceptual design and technical development to writing. This section details the contribution of the author to the three papers and acknowledges major contributions of others.

Chapter 2 The author was solely responsible for the conceptual design and writing of the article. Ottmar Edenhofer gave due support and indicated several important aspects to be included in the analysis. Nico Bauer reviewed several early drafts and provided helpful comments.

Chapter 3 The author developed the original idea, implemented the model and was responsible for writing the article. Lin Fan provided important input to the literature review, helped elaborating the approach, made corrections to early versions of the model, and contributed to the presentation and discussion of results. Wolf-Peter Schill clarified central aspects of the pass-through of CO2 prices, helped to refine the model, compiled parameters, made important contributions to the presentation and discussion of results, and encouraged many revisions following the reviews of the first draft. Ottmar Edenhofer gave due support and contributed in extensive discussions.

Chapter 4 The author implemented the model, elaborated the more specific research questions and was responsible for writing the article. Ottmar Edenhofer conceived the original idea, introduced the aspect of optimal pricing, and contributed in extensive discussions. Kai Lessmann helped developing the model, provided important input related to game theory, gave extensive feedback to early drafts of the article, and had a watchful eye on the details and formalities. Nico Bauer critically reviewed all aspects concerning energy system specifics, corrected a fundamental error in emission accounting, and made important contributions in calibrating the model.

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