Germany's dash for coal: exploring drivers and factors

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Michael Pahle
Potsdam Institute for Climate Impact Research
PO Box 601203, 14412 Potsdam, Germany
michael.pahle@pik-potsdam.de
Tel.: +49-331-2882687

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 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.

Keywords

Germany; dash for coal; investments in liberalized electricity markets

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 & 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 & 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 & 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 & 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 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.

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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.

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 is 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.

2. Investments in generation capacity

In this section data of historic and recent investments in generation capacity is 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 & Kuhnhenne (2006), Matthes (2000), and Brunekreeft & 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 & 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

[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.

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 (Figure 1).

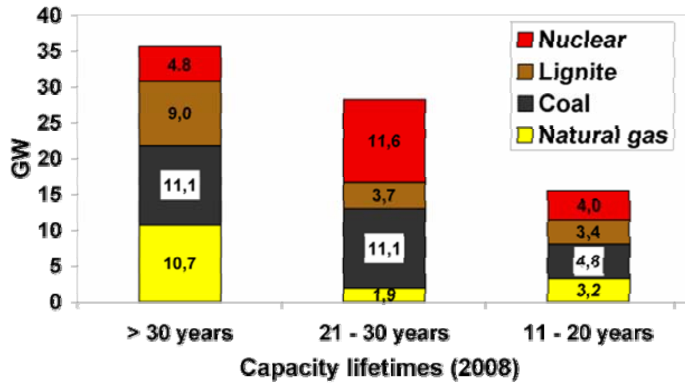

Figure 1: Age structure of German fossil and nuclear power plants
Source: Kjärstad & Johnsson (2007)

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 & 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 & 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 (Figure 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 & Bauknecht 2006). Lignite accounted for around 1.6 GW, and hard coal hardly played a role at all.

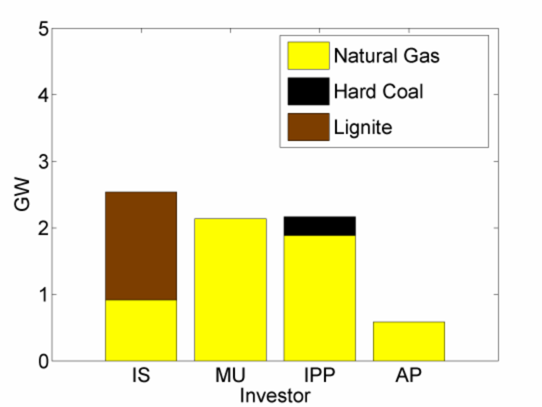

Figure 2: Fossil power plants commissioned 2001-2008

Sources: BDEW (2007), UBA (2009a)

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: 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 & 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 (Figure 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 GW to 14 GW and for lignite from 3.4 GW to 5.9 GW.

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

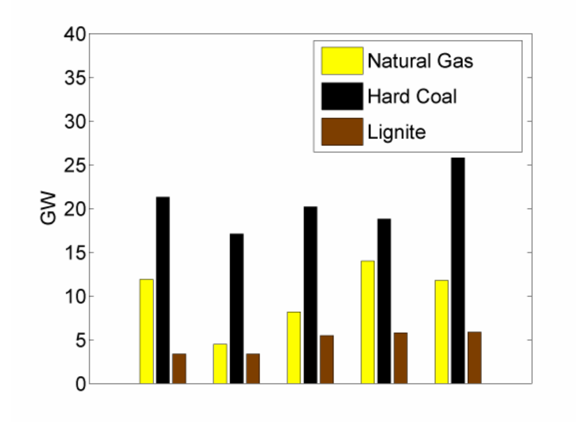

Figure 3: Fossil power plants planned or in construction
Sources: Schmitz (2007), BNetzA (2007), BNetzA (2008), BNetzA (2009), UBA (2009b)

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, 25-43.5GW in total, will eventually be built. Moreover, the variation between all sources included in Figure 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 (Figure 4); all plants are scheduled to go online in 2012 latest.

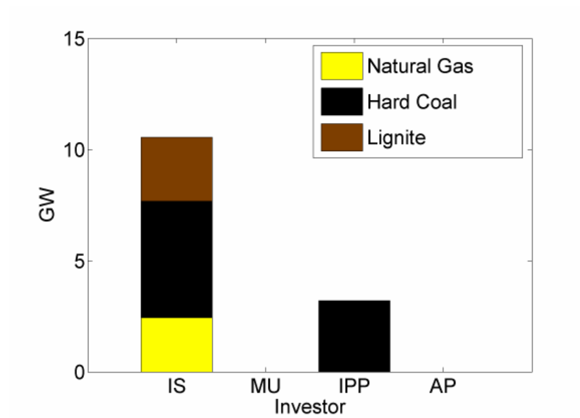

Figure 4: Fossil power plants under construction
Sources: DENA (2008), Hilmes (2009), BUND (2009)

Technology shares now show a completely different picture compared to 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 0.5-0.9GW (natural gas), 0.8-1.6GW (hard coal) and 0.8-2.2GW (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 & Bauknecht 2006) and the dominance of domestic players in the German electricity market. As Lambert & 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 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 & 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 a necessary condition. 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 to 7.4GW 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 can not 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 levelised 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 Andersson (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 & 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 Palmer (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 & 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 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 365kg/ 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 four 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 (75%-100%). Thus an extra stream of revenues is generated, which reduces both investment costs and risks (Hilmes & 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 & Schaffhausen 2008).

[4] For comparison with risks compiled by an investor see Vattenfall (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 365kg/MWh (natural gas) and 750kg/MWh (other technologies) multiplied by capacity and predefined full load hours, namely 7.500 hours for natural gas and hard coal and 8.250 hours for lignite; (b) free allocation are granted only for the duration of the second phase (2008-2012), i.e. for a maximum of five years. The former amendment can be seen as an explicit incentive for natural gas when compared to 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 550ppm and 450ppm 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.

3.2 Fuel costs

Another essential component of the cost structure are 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 a 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).

[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).

Fuel	Scenario	Scope	Period	Price inc. [%]*
Hard coal	IEA (2007)	OECD	2006-2030	-2.7 - 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**
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 -33.3

*real prices (base year); **assumption

Table 1: Coal and natural gas price scenarios

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 an 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.

3.3 Capital costs & 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 to 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

[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)

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.

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

*investments in generation capacity in brackets, **including networks

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

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 grandfathered ETS certificates. According to data from UBA (2009a) integrated suppliers operate more than 50% (~14.5GW) of all hard coal and nearly 100% (~21.2GW) 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.

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

3.4 Market & 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 (~21GW) and lignite (~21GW) capacities serving base load demand (see Figure 5)[10]. On top hard coal (~25GW) and natural gas (~15GW) plants supply intermediate load; peaks load is served by older gas turbines and oil. In addition, around 34GW 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.

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

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

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%.

Study	Demand red.
Ecofys (2008)	4.1 - 5.8%
BMU (2008a)	7.7 - 10.6%
UBA (2008a)	1.8 - 6.3%
EWI/EEFA (2008)*	-2 - 6%

*no explicit assessment of IKEP

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

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

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

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

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

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 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 & Nicolosi 2008).

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

[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.

example states that there exists no direct competition between power plant technologies of different load levels (BNetzA 2006).

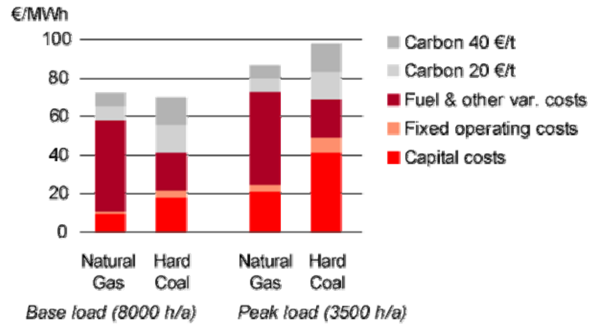

Figure 5: Long-term new entry costs in Europe based on E.ON assumptions
Source: Adapted from E.ON (2008)

Figure 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 Figure 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 8000h/a 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 Figure 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 & 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 frame-

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

works are currently 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 30MW lignite/hard coal pilot plant in Schwarze Pumpe. The capacity is envisaged to be extended to 375MW incurring total investments of around 1 billion Euro (Reuters.com 06.03.2009). RWE has announced a 450MW 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€ per 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).

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

**RWE WTA Technology, **E.ON Wilhelmshaven 50+*

Table 6: Technology efficiencies
Source: 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 & Bauknecht (2006), who highlight that strong technological advances are expected for 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 to 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 & 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 35GW 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

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

appropriate incentives for companies to make sufficient investments; see for example Ziesing & Matthes (2003) for an early, and DENA (2008) for a recent contribution. 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 7.4GW are estimated to go offline by 2012 (Table 7)[16]. Moreover, for the same period energy companies have announced to close down around 2GW of lignite, 1.5GW of coal and 0.1GW of natural gas capacity (BNetzA 2008).

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

*calculated based on remaining quota and annual output of the last operative year

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

Hilmes & 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 & 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 eco-

[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 Figure 5).

nomic 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 (Figure 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 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 south-west (Isar) where coal is not a cost-efficient alternative[19]. So only in this case, limited by location factors "inherited" from nuclear technology, naturals 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.

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

[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.

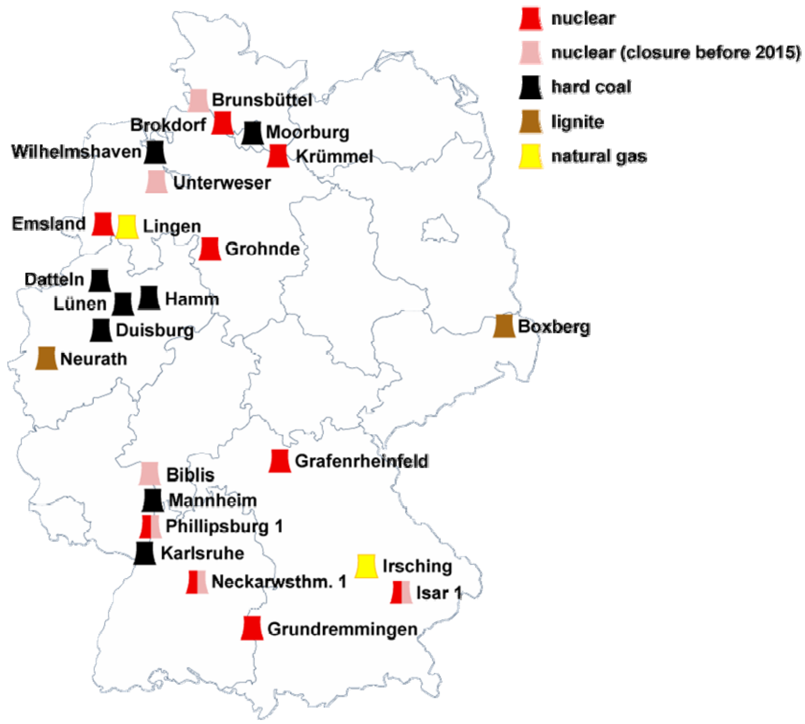

Figure 6: Locations of fossil (in construction) and nuclear power plants
Sources: Adapted from UBA (2009c); BUND (2009)

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 8.8GW that were turned down, but only gives a vague assessment of the rea-

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

sons. 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 & Metz 2006). The BMU also published an energy policy roadmap in early 2009 (BMU 2009) 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.

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% 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 to 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 Figure 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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