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Short expert report for the German Council for Sustainable Development

"Development of the German power plant fleet and meeting the electricity demand"

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CONTENTS

1 Introductory remarks 5

2 Development of electricity demand and supply 10

2.1 Development of electricity demand 10

2.2 Supply-side adaptation strategies 16

2.2.1 Changes in the existing power generation mix 16

2.2.2 Building of new power plant capacity that is endogenous to the market 20

2.2.3 Extending political support for the building of new power plant capacity 22

2.2.3.1 Preliminary remarks 22

2.2.3.2 Expansion of electricity production plants using renewable energies 22

2.2.3.3 The building of new CHP plants 23

2.2.3.4 Summary 26

2.2.3.5 Limiting greenhouse gas emissions in the long term and the subsequent effects on power plant expansion 27

3 Assessing options and uncertainties as a multi-dimensional problem 30

3.1 Introduction 30

3.2 The role played by the EU Emissions Trading Scheme 31

3.3 Quantitative electricity price effects 33

3.4 Assessing possible strategies 37

3.5 Dealing with uncertainties and dilemmas 44

LIST OF TABLES

Table 1 Development of electricity consumption in Germany from 2000 to 2007 according to sector 11

Table 2 Development of electricity production, electricity consumption and power plant capacities in Germany up to 2020 in the EWI/Prognos-Scenarios for the Global Energy Summit 13

Table 3 Capacity balance of the general electricity supply in Germany at the time of the annual highest load, 2002 to 2006 15

Table 4 Power plants planned or under construction with a capacity of 20 MW or above 21

Table 5 Model calculations for determination of primary energy savings and CO_2 emission reduction by means of CHP plants 25

LIST OF FIGURES

Figure 1 Development of electricity consumption, Gross Domestic Product and electricity productivity in Germany from 1990 to 2007 10

Figure 2 Power plant capacity implemented in the German electricity system, 1960 to 2006..... 17

Figure 3 Incumbent fossil power plants (natural gas, hard coal and lignite) taken out of operation up to 2020 in Germany 19

Figure 4 Specific emissions and new incumbent fossil power plants permitted under climate protection restrictions in Germany up to 2050..... 28

Figure 5 Hard coal, electricity, and carbon prices (Year Ahead Futures) and the short-term marginal costs of electricity production, 2003-2008 33

Figure 6 Short-term marginal costs of different fossil electricity production options for the continental European market..... 36

1 Introductory remarks

The issue of the future development of the power generation mix in Germany and how to meet the electricity demand is currently receiving much public attention, not least of all because of the controversies surrounding the building of new hard coal- and lignite-fired power plants. At the latest since the short analysis of the German Energy Agency (Deutsche Energieagentur, dena) on the power plant mix and network planning in Germany was published, an old discussion has once again been given priority on the energy policy agenda: the gap in the electricity supply ("electricity gap"). The basic line of argument is as follows: there will be substantial supply deficits or "unacceptable increases in electricity prices" if certain concepts of energy policy are not pushed through or implemented.

Current discussions on "electricity gaps" are conducted within a complex discursive environment characterised by the following aspects:

- The operators have a substantial economic interest in continuing the operation of existing nuclear power plants beyond the phase-out laid down in the German Federal Atomic Energy Act of 2002 (AtG 2002). This is because the combination of high electricity prices, low operation costs and widely written-off plants is expected to lead to high revenue and profits. At the same time the phase-out of nuclear energy means that the existing German power plant fleet loses a low-emission electricity production source.

- Based on the recently negotiated revision of the EU Emissions Trading Scheme, power plant operators can expect the free allocation of emission allowances to be phased out from 2013 onwards. The previous subsidisation of new power plants and the substantial windfall profits reaped by electricity producers will thereby come to an end. Some utilities are trying, for obvious reasons, to block the phase-out of the free allocation of CO_2 allowances.

- In order to achieve the medium- and long-term targets of climate policy currently under discussion, a drastic redesign of the electricity supply system is necessary (reduced level of consumption, new production options with renewable energies, combined heat and power, carbon capture and storage, redesign of infrastructures, etc.). However, there are still substantial uncertainties as to whether the intended targets can be met through the relevant political measures and what effects the applied and planned measures will actually have. Moreover, the applied instruments have to allow for effects that are partly very complex as well as complex market interactions.

- The age distribution of the German power plant fleet is such that substantial decisions on replacement and modernisation investments will have to be made in the decades ahead. The building of new power plants faces considerable problems in the light of massive increases in power plant and fuel costs (above all in the case of natural gas – a low-emission energy carrier – but undoubtedly also in the case of hard coal). In addition to

these problems, there is also the problem of an increasing lack of acceptance locally at the production and infrastructure sites as well as within the general political debate.

This complex environment is leading to some seemingly surprising positioning emerging in the discussion. Utility companies whose incumbent fossil power plants have high CO_2 emission reduction potentials are calling for the operating lifetimes of nuclear power plants to be extended, stressing the necessary and strong climate protection efforts. In turn, critics of nuclear power are calling for new (and environmentally damaging) fossil power plants to be built. The reference point for many of these discussions is the feared "electricity gap".

In a discussion paper[1] the authors recently attempted to demonstrate – also as a reaction to the dena study – what parameters and assessment approaches are of particular importance in finding whether an "electricity gap" will indeed open up or not. Some of the issues discussed are well-known (such as the future role of renewable energies, combined heat and power, or energy efficiency, especially electricity efficiency), but issues are also addressed which have not received much attention – such as the development of the existing fossil power plant fleet. In addition, the authors examined whether price signals could be found on the electricity markets which would support the notion of an "electricity gap" coming about in the short to medium term.

Above all because of pressure from climate policy, the electricity sector is on the verge of extensive restructuring in Germany as well as on the international level. Electricity use will have to become significantly more efficient, leading to a fall in the sale of electricity in the medium and long term – at least for Germany. At the same time, electricity production options which move beyond conventional methods of electricity production have to be integrated in the system, along with power plants using renewable energies and CHP. In addition to challenges set by climate policy, Germany has decided to stop using nuclear energy in the medium term (due to the associated risks), as laid down in the transparent and sufficiently flexible phase-out plan of the Federal Atomic Energy Act of 2002. The planned modernisation process of the German power plant fleet means that there are substantial opportunities for extensive restructuring in the decades ahead. However, the danger that an "electricity gap" will open up in the German electricity supply is being articulated in several position papers and analyses. According to these analyses, such a gap in supply is supposed to arise if new fossil power plants are not built "in sufficient quantity". Further, it is expected that the gap would widen if political targets relating to more efficient electricity use, expansion of the use of renewable energies and CHP-based electricity production are not met. If the assumption of an imminent "electricity gap" is shown to be reliable, the restructuring approaches currently being pursued for the electricity production system would result in a dilemma. If, on the one hand, a substantial amount of new power plants have to be built, the continued operation of

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[1] Matthes, F. Chr. und H.-J. Ziesing: Die Entwicklung des deutschen Kraftwerkparks und die aktuelle Debatte um die künftige Strombedarfsdeckung. Ein Diskussionsbeitrag. Berlin, 17 April 2008. (http://oeko.de/oekodoc/722/2008-196-de.pdf)

which would greatly jeopardise fulfilment of ambitious targets of climate policy, it will be questioned whether long-term targets of climate policy can in fact be met. Or, on the other hand, there will be a widening of the risks involved in the operation of nuclear power plants, directly through the extended operation of German nuclear power plants and indirectly through the impact on signals for international development, with all the additional risks involved in continued or widened use of nuclear energy (proliferation, etc.).

However, closer analysis of the assessment approaches and the data leads to the finding that development of the German power plant fleet must not automatically lead to this dilemma.

1. If the political targets related to increasing electricity efficiency, electricity production from renewable energies and CHP-based electricity production are pursued in earnest and supported by strong policies and measures, the phase-out of nuclear energy and the simultaneous building of new and very emission-intensive (coal-fired) power plants seem feasible. And yet feasibility on a scenario level is no substitute for necessary comprehensive and far-reaching political measures.

2. According to the current stage of discussions and development, further possible solutions will be available in the medium and long term. With the help of CCS technology, low-emission power plants can be also operated with emission-intensive energy carriers such as coal, at least for a transitional phase of one to two generations. However, this technology will only be commercially available post-2020. Retrofitting new large power plants with this technology in the short and medium term should be regarded as rather improbable within the current legal framework and for economic reasons.

3. In the case of (limited) delays in the implementation of measures related to energy efficiency, renewable energies and CHP, there are substantial flexibility options available to guarantee the security of electricity supply. The shutdown sequence of incumbent fossil power plants is flexible for substantial generation capacities and will result from the relevant market processes. The opening-up of a supply gap is not likely against this background and given the continued phase-out of nuclear energy. Nevertheless, the extended operation of incumbent fossil power plants can of course also lead to problems in terms of meeting short- and medium- term emission targets. However, the effects of the EU Emissions Trading Scheme, which “ensures” the compliance to the set emission targets, have to be incorporated in the assessment.

Against this background, the key challenge in redesigning the German electricity system is – at least in the short and medium term – less the possible opening up of an “electricity gap” and more the consequences of different reactions to potential supply deficits for climate policy. In spite of all the flexibilities of the electricity supply system, the question of whether it is possible to actually meet the set targets using the measures taken at present is still of crucial importance. After all, to fully achieve the target of doubling CHP-based electricity production requires an additional 60 to 70 billion kWh, making necessary the building of new CHP plants

with an electricity production capacity of 12,000 to 14,000 MW. It goes without saying that there are no alternatives to the ambitious strategies, policies and measures – motivated primarily by climate policy – related to energy efficiency, renewable energies, and CHP. In accordance with the relevant set targets they can and have to make a significant contribution to the future electricity supply. Yet it also needs to be ensured that the necessary investment decisions meet with acceptance from the general public.

Setting clear targets, sticking to them, and taking credible measures to make it possible for these targets to be met are a political responsibility. In terms of electricity production from renewable energies, a high level of credibility has already been reached, but in terms of electricity efficiency and CHP, the initiated measures have not been sufficiently credible to date. Essentially the political challenge and responsibility is to transfer the "statement-making" targets into planning security for the directly and indirectly affected actors of the electricity sector.

Electricity utilities above all have the responsibility to accept the politically set targets and general conditions, to not undermine them, and to not avoid their implementation. Indeed they are responsible for supporting them since it will also enhance the planning security for their own decisions – if the sector comprehensively participates. However, utilities will only readjust their processes of economic optimisation when general conditions have been politically set.

With all of this in mind, it is important not to forget that acceptance of the introduced measures and investments is of paramount importance, not least of all given that the German public is highly sensitised towards environmental policy and more recently climate policy. The necessary acceptance of political instruments and investments in electricity production plants and infrastructures (which is also especially true for transport and distribution networks) can only be developed with transparency, clear target consistency and credible measures across the board.

The question also arises as to what political measures are useful and necessary in order to avoid a potential "electricity gap" or rather what consequences might result from the use of particular measures. Such a discussion is constructive – irrespective of whether and for what time horizon an "electricity gap" is anticipated.

In summary, it can be concluded that in order to meet the far-reaching challenges of restructuring the electricity system (not only) in Germany, an intensive dialogue as well as strong political and company efforts are necessary in the long term, and should not only concentrate on the electricity sector but rather the total energy industry system.

In the discussion paper published in April 2008, the authors attempted to illuminate the different aspects involved in the complex discussions about the "electricity gap". But given the short nature of the paper, many issues had to be left open that should be incorporated in the ongoing discussion process. This short expert report for the German Council for Sustainable Development is intended to serve this purpose.

This short expert report shall initially address the issue of future “quantitative” development of electricity demand and supply, consistently differentiating between electricity and capacity in the process.

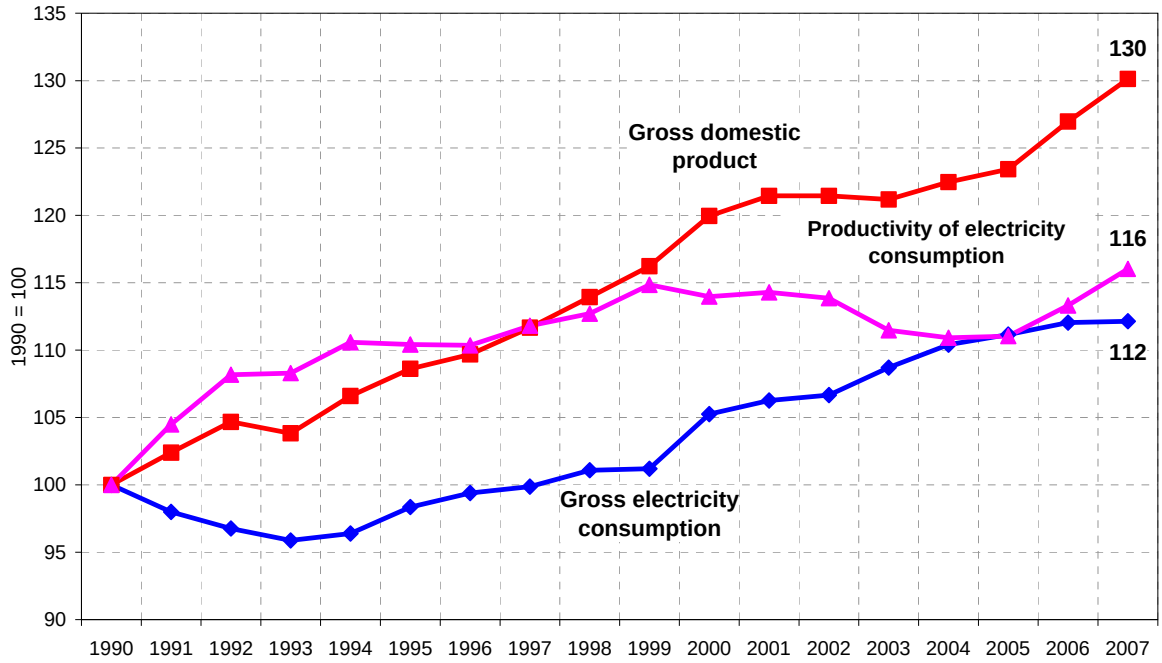
2 Development of electricity demand and supply

2.1 Development of electricity demand

A new scenario for electricity demand could not be developed within the scope of this short expert report. The authors' discussion paper should be consulted for references to the current discussion and is complemented by the following thoughts and considerations which also need to be taken into account:

Of fundamental importance to the assessment of the future security of electricity supply is the projected development of the electricity demand. From 1990 to 2007 electricity demand in Germany increased by 0.7% on average each year. Only in recent years has the increase in electricity demand significantly slowed, with the result that the macroeconomic productivity of electricity consumption (electricity productivity) could be substantially improved. Whether a more long-term trend has been initiated here will have to remain to be seen.

Figure 1 Development of electricity consumption, Gross Domestic Product and electricity productivity in Germany from 1990 to 2007



Sources: Statistisches Bundesamt, AG Energiebilanzen, bdew

When assessing the future development of electricity consumption, it is useful to examine the resulting changes in the electricity productivity. An approximate 10% fall in gross electricity consumption up to 2020 compared to 2007 – as pursued by the German federal government – would mean that the electricity productivity in this phase would have to increase by 2.5 % on average per year. If this reduction can first be realised by 2030, a 2% increase in the electricity productivity would still be necessary each year. By contrast, if electricity consumption does not to change up to 2030 compared to 2007, the electricity productivity will have to in-

crease at a significantly quicker pace (1.6 % p.a.) than was the case on average in the past (0.9 % in the period from 1990 to 2007). In the total period from 2007 to 2030, an average macro-economic growth of 1.6 % p.a. is expected.

A substantial increase in the electricity productivity compared to previous years is therefore imperative if the aim is to relieve the burden on the production demand, in this case the electricity demand. However, this also means that special attention has to be paid to a policy which aims to increase electricity efficiency. After all, levels significantly exceeding 2% were reached in 2006 and 2007. Every reduction in electricity consumption by one percent could save around 1500 MW of power plant capacity. The extent of the "electricity gap" is insofar a direct product of the success – or lack of success – of a policy on electricity saving.

Overall there are several differences between the individual sectors with regard to the development of electricity consumption in Germany. In the period from 2000 to 2007, electricity consumption has fallen above average in public services and has risen in the trade and commerce sector, the residential sector and in industry, whilst consumption and losses have even decreased in the transformation sector.

Table 1 Development of electricity consumption in Germany from 2000 to 2007 according to sector

	2000	2001	2002	2003	2004	2005	2006	2007	2000-2007
	TWh								Changes (% p.a.)
Transformation consumption and losses	78.2	77.4	71.2	73.6	76.1	77.9	77.4	76.5	-0.3
Own use by power plants	38.1	38.2	37.4	38.8	38.5	39.0	39.6	39.3	0.5
Electricity used for pumped storage	6.0	6.0	6.3	7.7	9.3	9.5	9.0	9.1	6.0
Transmission and distribution losses and sector non specified	34.1	33.2	27.5	27.1	28.2	29.4	28.8	28.2	-2.7
Final consumption	501.4	507.7	516.2	525.0	531.9	534.2	539.6	541.0	1.1
Industry	239.1	240.3	243.1	244.8	248.5	249.7	253.7	255.6	1.0
Transport	15.9	16.0	16.0	16.1	16.2	16.2	16.3	16.3	0.3
Public Services	40.1	41.0	42.2	43.9	44.5	44.6	44.9	45.0	1.7
Agriculture	7.5	8.0	8.0	8.2	8.3	8.3	8.3	8.5	1.8
Residential	130.5	134.4	136.5	139.1	140.4	141.3	141.5	140.5	1.1
Commercial and services	68.3	68.0	70.4	72.9	74.0	74.1	74.9	75.1	1.4
Gross electricity consumption	579.6	585.1	587.4	598.6	608.0	612.1	617.0	617.5	0.9

Source: bdew

In the meantime there are indications of stagnating trends in the residential sector, trade and commerce and in public services. The question as to whether this will evolve into a more long-term trend, as was the case with the intensity of electricity consumption, has to remain open.

It should not be overlooked that almost all of the electricity consumption sectors still have **high electricity saving potentials**. According to estimations, the measures for reducing elec-

tricity consumption by 2020 described in the Meseberg package should lead to savings of as much as 30 billion kWh, with the use of more efficient household devices contributing around 16 billion kWh and the use of electric motors in industry almost 15 billion kWh. The use of night storage heaters – also suggested in the scope of this programme – could lead to a further reduction of up to approx. 20 billion kWh. There are also high saving potentials in the avoidance of stand-by losses, which in the residential sector alone is estimated at 10 billion kWh. The estimates of the German Association for Electrical, Electronic and Information Technologies (Verband der Elektrotechnik, VDE) are also of interest: the (economic!) saving potential for lighting is estimated at 56 %. In terms of the electricity consumed for lighting purposes – which according to the data of the German Association of Energy and Water Industries (Bundesverband der Energie- und Wasserwirtschaft, BDEW) amounted to almost 50 billion kWh in 2006 – savings could amount to around 27 billion kWh. The Association for Electrical, Electronic and Information Technologies assumes saving potentials of around 22 billion kWh if electronic speed control is used in industrial motor drives instead of mechanical valves. Only when these saving potentials are added together is a volume of nearly 110 billion kWh reached. However, it is not expected that all of these potentials will be completely exhausted, even within the next 10 to 20 years. But exhausting half of the potentials by 2020 would alone lead to a reduction of around 50 billion kWh, thereby directly bringing about a corresponding increase in the macroeconomic intensity of electricity consumption. Related to the development of the total electricity consumption, effects brought about by increases in production are counteracted by increasing market penetration of new appliances, especially in the IT sector.

Within the context of the discussion on the “electricity gap”, it should be borne in mind that the necessary power plant capacities are determined by the capacity demand and not primarily by the electricity demand itself and its impact on the highest load. When examining past data it is clear that electricity consumption and the highest load have developed very differently in part. According to UCTE data, the highest load (Highest Load on the 3rd Wednesday calculated to represent 100% of the national values) barely changed from 1996 to 2006 (80672 MW in 1996 compared to 80750 MW in 2006), whilst the gross electricity demand rose by almost 13 % in this period. According to data from the Association of German network operators (Verband der Netzbetreiber, VDN), the highest load in 2006 was at 77.8 GW even almost 2 GW below the highest load in 2002 (79.7 GW), whilst electricity consumption increased by 5 % in the same time period.

Against this background it cannot be ruled out that this trend will continue in the future. This means that even in the case of similarly low increases in electricity demand, the growth of the highest load (which is decisive for capacity) more or less lags behind. Highest load growth should in principle remain minimal even without effective and invasive electricity efficiency policy, which suggests that the current German power plant fleet will be in a position to meet the capacity and electricity demand for many years still. At the same time, a fall in electricity demand itself does not automatically lead to a fall in the highest load. This holds true, for ex-

ample, for electricity uses that were intended to be used in weak load periods and would not then have an impact on the highest load. In contrast to, for instance, the use of more efficient household devices, electrical motors and pumps as well as through the avoidance of stand-by losses, the use of night storage heaters would not have an impact on the highest load development in this respect.

EWI/Prognos scenarios – which were published in 2007 for the Energy Summit process on behalf of the German Chancellery – give an impression of the possible future development of electricity consumption, electricity production and power plant capacities. One of the most important terms of reference on which these scenarios were based was the assumption that macroeconomic energy productivity in Germany shall double up to 2020 compared to 1990 levels, suggesting that from 2005 onwards energy productivity would have to increase every year up to 2020 by an average of around 3%. Since it cannot be ruled out that the target will be not met, a so-called 2% alternative to the "Coalition Agreement" scenario (Koalitionsvereinbarung, KV) was assessed. The results are summarised in Table 2.

Table 2 Development of electricity production, electricity consumption and power plant capacities in Germany up to 2020 in the EWI/Prognos-Scenarios for the Global Energy Summit

	2005	2006	2007	Szenario 2020							
				CA	2%-Var.	RE	NPP	CA	2%-Var.	RE	NPP
	TWh							Changes 2020 vs. 2007 in TWh			
Gross electricity production	611.8	636.8	636.5	543.9	654.3	541.4	547.8	-92.6	17.8	-95.1	-88.7
Imports - Exports	-8.5	-19.8	-19.0	1.8	10.0	-8.2	-16.7				
Gross electricity consumption	620.3	617.0	617.5	542.1	644.2	549.6	563.9	-75.4	26.7	-67.9	-53.6
	Installed Capacity in GW							Changes 2020 vs. 2005 in GW			
Gross Installed Capacity	140.3	138.6	.	151.2	170.6	162.8	152.0	10.9	30.3	22.5	11.7
Hydro	12.1	10.1	.	12.5	12.5	12.5	12.5	0.4	0.4	0.4	0.4
Nuclear	21.5	21.2	.	7.1	7.1	7.1	21.5	-14.4	-14.4	-14.4	0.0
Hard Coal	29.4	28.7	.	25.2	30.1	25.0	19.2	-4.2	0.7	-4.4	-10.2
Lignite	22.0	21.8	.	15.7	15.3	15.7	15.7	-6.3	-6.7	-6.3	-6.3
Natural Gas	23.3	21.2	.	32.6	47.6	29.3	24.9	9.3	24.3	6.0	1.6
Oil	5.5	5.5	.	3.2	3.2	3.2	3.2	-2.3	-2.3	-2.3	-2.3
Other fuels*	6.0	6.7	.	13.8	13.8	19.4	14.0	7.8	7.8	13.4	8.0
Wind	18.4	20.6	.	32.7	32.7	37.7	32.7	14.3	14.3	19.3	14.3
Solar	2.1	2.7	.	8.2	8.2	12.5	8.2	6.1	6.1	10.4	6.1
Geothermal	0.0	0.0	.	0.2	0.2	0.5	0.2	0.2	0.2	0.5	0.2

Notes: * including Biomass.

Sources: EWI, Prognos (2007)

In the context of the "electricity gap" discussion, it is interesting that in the basic scenarios – the "Coalition Agreement (CA)", "Greater use of renewable energies (RE)" as well as "Lifetime extension for nuclear power plants (NPP)" – in which electricity consumption falls up to 2020 by 9% to almost 13% compared to 2005 (the reference year of the EWI/Prognos study)

with gross electricity production lying somewhere around minus 11 % in both cases, the power plant capacity in place in 2005 also falls (except in the case of renewable energies and natural gas), although the capacity of nuclear power plants decreases by more than 14 GW (with the exception of the NPP scenario) in accordance with the requirements of the phase-out plan. This also means, however, that in the current power plant fleet a significant amount of outdated and particularly inefficient power plant capacities could be shut down if the operating lifetimes are extended and the building of new power plants continues to be beyond question.

A somewhat more differentiated picture arises with the 2% alternative to the CA scenario. In this case, a slight growth in electricity consumption by approx. 0.4 %/a compared to 2005 (0.2 %/a compared to 2007) and an increase in power plant capacity of around 20 GW compared to the CA scenario are expected. Even in this case it would be possible to phase out the power plant capacity of coal-fired and nuclear power plants, but a substantial amount of new natural gas-fired power plants would have to be built if the development of renewable energy power plants remains unchanged.

It is clear that in scenarios that assume a fall in electricity consumption, the demands on the power plant capacity that has to be provided also fall. However, there is no linear correlation in this case because (as mentioned above) not all electricity demand or fall in electricity demand is relevant to the highest load. But even if that were the case, it cannot directly be traced back to changes to the power plant capacities to be provided (maximum capacity). What is necessary is not the power plant capacity in itself, but rather a **guaranteed capacity** to meet the highest load in each case. There are very great differences between the different power plant types in this regard. Whilst the guaranteed capacity of conventional thermal power plants has an order of magnitude of around 90 % of the maximum capacity, the contribution to capacity of, for example, photovoltaics is very low (only a few percentage points) and that of wind power plants is limited.

However, the degree of freedom in forming estimates has a substantial impact on the final assessment of capacities. The authors demonstrate in the discussion paper that there are very often differences of GW that were in the double digits.

Furthermore, a huge gap is emerging between the total power plant capacity available domestically for the general electricity supply and the highest load (Table 3): If around 77 % of the total power plant capacity of the general electricity supply in Germany in 2002 were classified as guaranteed capacity, then it would be just under 70% in 2005 and 2006. In 2002 only 24.4 GW was considered to be guaranteed capacity; in 2006, however, it was 38.1 GW. This can be best attributed to the substantial development of “non-usable capacity”, which is above all explained by wind power plants in the VDN assessment. Failures, revisions and reserves for system services were added to the sum as non-guaranteed capacity. In spite of the increase in non-guaranteed capacity the remaining capacity not needed to meet the annual peak load rose from 6 to 8 GW from 2002 to 2006.

Table 3 Capacity balance of the general electricity supply in Germany at the time of the annual highest load, 2002 to 2006

	2002	2003	2004	2005	2006
	GW				
Gross domestic capacity	**105.8**	**111.4**	**114.6**	**119.4**	**124.3**
- Non-usable capacity	12.2	16.5	17.9	22.8	23.8
- Outages		3.0	2.8	4.1	4.0
- Revisions	5.1	1.9	0.7	2.7	2.4
- Reservers for system services	7.1	7.0	7.2	7.1	7.9
= Guaranteed capacity	**81.4**	**83.0**	**86.0**	**82.7**	**86.2**
Remaining capacity	1.7	6.7	8.8	6.0	8.4
Peak load of public electricity supply	**79.7**	**76.3**	**77.2**	**76.7**	**77.8**
	Structure in %				
Gross domestic capacity	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
- Non-usable capacity	11.5	14.8	15.6	19.1	19.1
- Outages	0.0	2.7	2.4	3.4	3.2
- Revisions	4.8	1.7	0.6	2.3	1.9
- Reservers for system services	6.7	6.3	6.3	5.9	6.4
= Guaranteed capacity	**76.9**	**74.5**	**75.0**	**69.3**	**69.3**
Remaining capacity	1.6	6.0	7.7	5.0	6.8
Peak load of public electricity supply	***75.3***	***68.5***	***67.4***	***64.2***	***62.6***

Sources: VDN, annual reports

The important question to ask is whether the large margin between the highest load and the total installed power plant capacity for the general electricity supply (amounting to a capacity of almost 50 GW, not enough to meet the highest load) has to be an unchanging margin or even has to increase. Or whether and using which measures this capacity could be used not only for electricity production, but also for the purpose of load guarantee. It was not possible to answer this question within the scope of this short expert report; nevertheless further analysis is expressly recommended.

Summary: A fall in electricity consumption of around 10 % up to 2020 seems to be fundamentally feasible, given the electricity saving potentials in all sectors. It can be confidently assumed that the currently rather high electricity price is triggering incentives to use electricity more frugally. This effect would be even greater if the feared “electricity gap” really does come about, in the wake of which or even as a precursor to which electricity prices would strongly rise. In this sense, the “electricity gap” – at least theoretically – would not only be part of the problem but also part of the solution at the same time. However, difficulties in adapting to this situation and distribution problems are also likely to affect this process.

So as to avoid such difficulties and independent of the autonomous reaction mechanisms outlined above, the implementation of political measures that aim at more efficient electricity use – key points for an integrated energy and climate programme as agreed upon in Meseberg in August 2007 – seems to be absolutely essential. This is even more so the case in light of the fact that no reversal in the electricity consumption trend has been shown to date and the

measures aiming to improve electricity efficiency are only partly put into practice and/or only after a delay. The current status of negotiations within the Federal Grand Coalition makes it doubtful whether these parts of the programme can be realised in practice.

Therefore, as a precaution it might be advisable to be on the safe side and assume only a fall in electricity consumption of around 6 % up to 2020. Using 2007 as the base year with a gross electricity consumption of 617.5 TWh, the target for 2020 would be 580 TWh; if zero electricity export is assumed, it is then the equivalent of gross electricity production. If the average internal power plant consumption is assumed to be approx. 6 %, the net electricity production would be 545 TWh (2007: 597.3 TWh).

Under the (conservative) assumption of a similar development of electricity demand and highest load, it would fall from a little above 78 GW in 2006 to approx. 73 GW. If the remaining free capacity is updated (as in the dena assessment) to just under 8 % of the highest load, the required guaranteed capacity would be just under 79 GW in 2020 – approx. 7 GW less than in 2006.

2.2 Supply-side adaptation strategies

In assessing the future development of power plant supply, the following three aspects are to be considered:

- the existing power plant fleet and the changes to it arising from an
- additional increase in new power plant capacity that is endogenous to the market, and
- politically supported building of new power plant capacity.

In the following analysis, adherence to the phase-out plan for nuclear energy laid down in the Federal Atomic Energy Act is assumed and possible solutions involving increases in electricity imports are avoided.

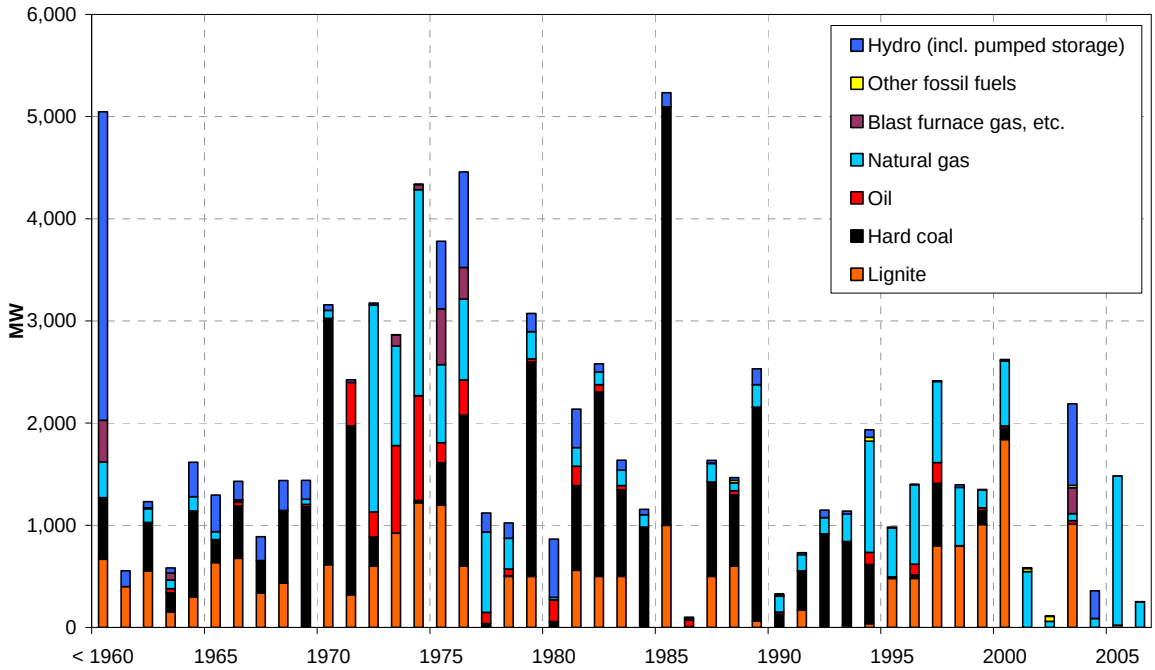
2.2.1 Changes in the existing power generation mix

The German power plant fleet is above all distinguished by two different trends with regard to conventional power plants (fossil and hydroelectric power plants) (see Figure 5):

- Power plants in the former West German states generally have capacities which will reach 40 to 60 years of operating lifetimes in the second decade of this century. However, it should be noted that all power plants put into operation before 1983 were fitted with flue gas treatment equipment and therefore had to be fundamentally modernised.
- The power plant fleet in the new federal states has been fundamentally modernised from the mid-1990s onwards, meaning that modernisation investments (for the power

plant units that were not shut down but rather restored for the mid-1990s) only have to be considered post-2020.

Figure 2 Power plant capacity implemented in the German electricity system, 1960 to 2006

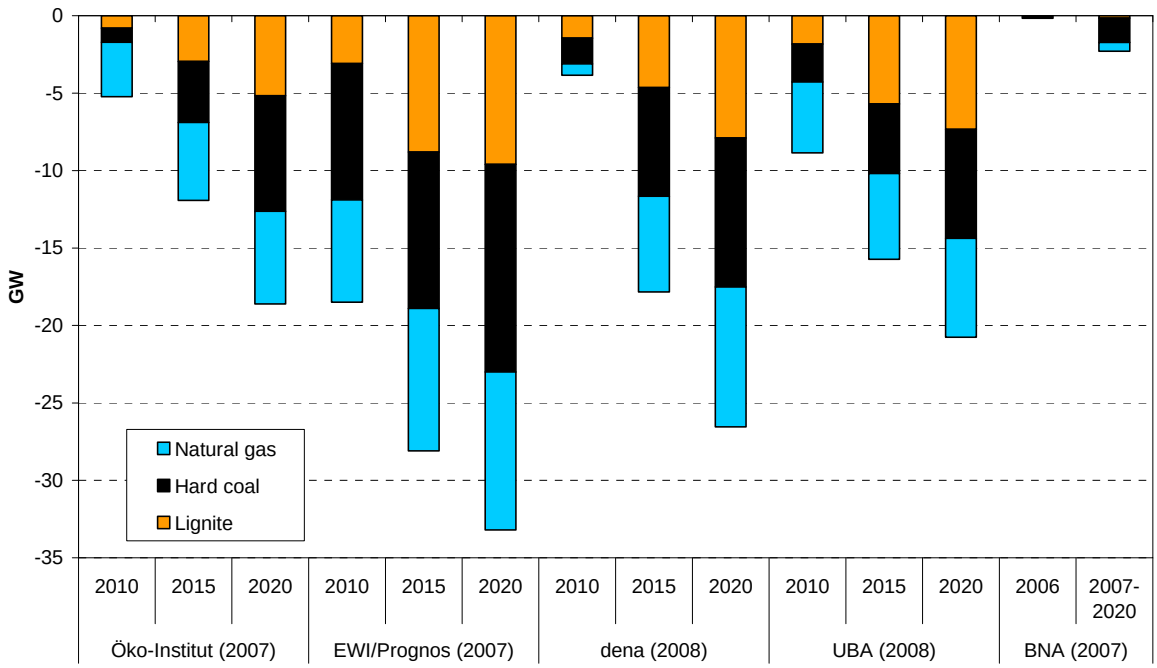


Sources: Platts, authors' own calculations

There is a wide spectrum of estimates concerning the need to replace fossil power plants. A comparison of current assessments shows that the various estimates for the removal of fossil power plants from operation up to 2020 differ by 10 to almost 20 GW (

Figure 3). However, wide-ranging estimates are in no way uncommon since complex estimates are necessary for determining the technical condition and economic performance of different block power plants in order to gauge the power plant shutdowns that can be expected.

Figure 3 Incumbent fossil power plants (natural gas, hard coal and lignite) taken out of operation up to 2020 in Germany



Sources: EWI/Prognos (2007), Öko-Institut/arrhenius (2007), BNA (2007), dena (2008), UBA (2008)

In the case of corresponding price levels on the relevant wholesale markets, retrofitting investments are possible for nearly all power plant capacities, which can considerably extend the technical and economic operating lifetimes of plants. In the OECD area, for example, there is a whole array of plants that are operated for up to 60 years or more. A key factor in international comparisons of the operating lifetimes of power plants is cost-intensive retrofitting with flue gas treatment equipment. Restrictions on the further operation of old power plants are not relevant for Germany (but are in the UK, for example) since they were all retrofitted with flue gas treatment equipment at an early stage. If it is assumed that economic operation of plants put into operation after 1980 should to be possible up 2030 at least or and that the plants put into operation between 1970 and 1980 can continue operation up to 2020 or even longer (with the help of retrofitting investments if necessary), the flexibility potential of the existing power plant fleet is then more than 20 GW. Even if it is taken into account that retrofitting investments are only economically feasible for a share of these plants (these power plants still generate contribution margins, by means of which such investments can be recovered financially), the remaining power plant capacities can still produce 10 to 20 GW, which can guarantee sufficient electricity production for certain periods of time. Nevertheless, it should be pointed out that the available flexibility potential of the existing power plant fleet is not unlimited. In all events, there has to be a substantial amount of sufficient investments on the supply and demand side for 2030 at the latest.

2.2.2 Building of new power plant capacity that is endogenous to the market

Alongside the planned development of additional fossil CHP plants, a large number of new fossil power plant projects are under discussion. The planning and implementation status of these power plant projects (with and without CHP) differs greatly and a considerable number of these projects are highly controversial. An overview is provided in Table 4, based on data published by the BDEW.

As of April 2008, the implementation status in terms of general supply was:

- 24 power plants are being built in total, with a total capacity of approx. 11.5 GW (entering operation in 2012 at the latest) and
- a further 36 power plants are being planned, with a capacity of approx. 23 GW.

Since the building of the Vattenfall power plant in Moorburg (Hamburg) has been approved, which will have a capacity of 1.654 MW, it can be regarded as a certainty that the plants now being built (with a total capacity of 11.5 GW) will be put into operation. 5.8 GW of the plant capacity now under construction is to come from hard coal-fired power plants; approx. 2.8 GW from lignite-fired power plants and 2.4 GW from natural gas-fired power plants and 0.5 GW from all other plants.

Added to that are the power plants put into operation in 2007 in Germany, which have a capacity of 2.385 MW. For the period from 2007 to 2012 a capacity of nearly 14 GW can be expected from new power plants. This means a guaranteed capacity of approx. 12 GW.

Table 4 **Power plants planned or under construction with a capacity of 20 MW or above** (source: bdew, as at April 2008)

Company	Power Plant	Capacity in MW	Energy source	Estimated start of operation
Vattenfall Europe	GuD-HKW Hamburg-Tiefstack*	125	Natural Gas	2008
Vattenfall Europe	Schwarze Pumpe* (Pilo plant; CO_2-clean plant)	30	Lignite	2008
Vattenfall Europe	Rüdersdorf*	30	Waste	2008
swb, Bremen	Standort Hafen*	28	Waste	2008
Infraserv Knapsack/ Sotec	Hürth*	30	Waste	2008
Vattenfall Europe	Rostock*	20	Waste	2008
E.ON / EWE / Vattenfall Europe	Nordsee / vor Borkum	60	Wind	2008
RWE Power	Lingen*	875	Natural Gas	2009
E.ON / N-ERGIE / Mainova / HEAG	Irsching 5*	820	Natural Gas	2009
Gichtgaskraftwerk Dillingen (STEAG Saar Energie, VSE, Rogesa)	Dillingen/ Dillinger Hütte*	90	Blast furnace gas	2009
Würzburger Versorgungs-und Verkehrs GmbH (WVV)	GuD-HKW Würzburg*	50	Natural Gas	2009
Infraserv Höchst	Industriepark Höchst*	70	Waste	2009
MVV Energie	Mannheim / Friesenheimer Insel / Kessel 6*	23	Waste	2009
E.ON Wasserkraft	Waldeck I (Edersee)* (Replacement)	70	Pump storage	2009
E.ON Wasserkraft	Waldeck II (Edersee) (Enlargement)	20	Pump storage	2009
Rheinkraftwerk Albbruck-Dogern (RADAG)	Albbruck-Dogern* (Enlargement)	24	Hydro	2009
wpd AG	„Baltic 1“, Ostsee Offshore-Windpark	53	Wind	2009
juwi	Solarpark „Waldpolenz“ Brandis (near Leipzig)*	40	Solar	2009
Solar Projekt GmbH	Turnow-Preilack	50	Solar	2009
RWE Power	BoA Neurath*	2,100	Lignite	2010
STEAG / EVN	Duisburg-Walsum 10*	700	Hard coal	2010
Gazprom (RUS) / Soteg (LUX)	Eisenhüttenstadt	800	Natural Gas	2010
Nuon	Frankfurt a.M./ Industriepark Griesheim	450	Natural Gas	2010
BKW FMB Energie (CH) Advanced Power (CH) Siemens Project Ventures	Bocholt	400	Natural Gas	2010
Aluminium Oxid Stade (AOS)	Stade-Bützfleeth	30	Natural Gas	2010
Salzgitter AG	Watenstedt	220	Blast furnace gas	2010
Energiedienst (EnBW)	Rheinfelden (upgrade)*	74	Hydro	2010
Stw. Ulm (SWU)	Blaubeuren	45	Pump storage	2010
Trianel EET/ Prokon Nord	Borkum West II / Offshore Windpark	400	Wind	2010
E.ON Energie	Datteln 4*	1,055	Hard coal	2011
EnBW	Karlsruhe/ Rheinhafen*	850	Hard coal	2011
E.ON / Gazprom	Lubmin	1,200	Natural Gas	2011
Iberdrola	Mecklar-Marbach (Nordhessen)	1,000	Natural Gas	2011
Iberdrola	Lauchhammer (Brandenburg)	1,000	Natural Gas	2011
E.ON Energie	Irsching 4*	530	Natural Gas	2011
EnBW	Karlsruhe/ Rheinhafen	465	Natural Gas	2011
Vattenfall Europe	Boxberg*	675	Lignite	2011
RWE Power	Hamm*	1,500	Hard coal	2011/2012
EnBW	Niedersachsen	330	Pressurised storage	2011/2012
Vattenfall Europe	Hamburg-Moorburg*	1,654	Hard coal	2012
Dong Energy	Lubmin	1,600	Hard coal	2012
Electrabel/ BKW FMB Energie AG	Wilhelmshaven	800	Hard coal	2012
Electrabel	Stade oder Brunsbüttel	800	Hard coal	2012
Südweststrom/ Iberdrola	Brunsbüttel	1,800	Hard coal	2012
Trianel Power	Krefeld/ Chemiepark Krefeld-Uerdingen	750	Hard coal	2012
Trianel Power	Lünen	750	Hard coal	2012
Stw. Düsseldorf	Düsseldorf-Lausward	400	Hard coal	2012
STEAG	Lünen (not yet decided)	690	Hard coal	2012
Vattenfall Europe	Berlin (site not yet decided)	800	Hard coal (Natural Gas)	2012
Kraftwerke Mainz-Wiesbaden (KMW)	Mainz/ Ingelheimer Aue	760	Hard Coal	2013
MIBRAG	Profen	660	Lignite	2013
E.ON Energie / Stw. Hannover	Staudinger 6 (Großkrotzenburg)	1,100	Hard Coal	2013
GKM	Mannheim	910	Hard Coal	2013
BKW FMB Energie (CH)/ Advanced Power (CH)	Dörpen (Emsland)	900	Hard Coal	2013
GETEC Energie AG	Brunsbüttel/ Bayer Industriepark	800	Hard Coal	2013
E.ON Energie	Wilhelmshaven	500	Hard Coal	2014
RWE Power	IGCC-Kraftwerk (CCS) (Site not yet decided)	450	Hard coal (Lignite)	2014
Dow Chemicals/ EnBW	Stade	1,000	Natural Gas	2014
Vattenfall Europe	GuD-Lichterfelde	150	Natural Gas	2016
E.ON Energie/ Stw. Kiel	Kiel (Ostufer)	800	Hard Coal	2018
Total	**60 Power Plants**	**34,406**		
among this	**under construction**	**11,463**		
Power plants with yellow colour are under construction redarding BDEW.				

2.2.3 Extending political support for the building of new power plant capacity

2.2.3.1 Preliminary remarks

Renewable energy sources and combined heat and power were some of the options for electricity production in Germany developed with the help of a high level of political support and pressure. The associated political targets are comparatively clear:

- the Federal Renewable Energy Sources Act (RES; Erneuerbare-Energien-Gesetz, EEG) aims to "further increase the share of renewable energies in the electricity supply to 25 to 30 percent up to 2020, and to increase it continuously after that date", whilst
- the Federal Combined Heat and Power Act (CHP Act; Gesetz zur Förderung von KWK) aims to double the share of CHP-based electricity production to approx. 25 percent in 2020.

This means that at least half of the electricity production expected in 2020 will be met by renewable energies and CHP if the above two targets are successfully realised. Compared to the current CHP-based share of electricity production (approx. 13 %) and that of renewable energies (approx. 14 %), added together and taking into account an overlap of around 26 %, the contribution of electricity production is doubled or – in absolute terms – there is an additional contribution (assuming a constant level for electricity production up to 2020) of at least approx. 150 billion kWh. Subsequently more than half of the total electricity production would be determined politically. In the following, perspectives concerning electricity production from renewable energies and the conversion of CHP to electricity will be discussed.

2.2.3.2 Expansion of electricity production plants using renewable energies

Taking into account different scenarios (Nitsch et al. 2007, dena 2005) as well as current developments (e.g. related to offshore wind power), the electricity production capacities of the regenerative power plant fleet can be assumed to amount to 65 GW by 2020 and around about 95 GW by 2030 (approx. 35 GW and 65 GW more than in 2006 respectively). This would mean an electricity supply of approx. 170 TWh in 2020 and around 250 TWh in 2030. For 2020, this means a 25-30 % share of the electricity supply (depending on electricity demand), thereby falling within the range stated in the scenarios, on which the current targets for the use of renewable energies in overall electricity production are based. Compared to the corresponding production in 2006, the share is 100 TWh higher in 2020 and approx. 180 TWh higher in 2030.

In terms of the capacity demanded, renewable energies could provide – under favourable basic conditions – a guaranteed capacity of 15 GW (19 GW) in 2020 (2030). Compared to 2005 levels, that means an additional capacity margin of 9 GW and 12 GW respectively.

Conclusion: It is likely that renewable energies will contribute substantially to meeting the electricity demand by 2020 given the Federal RES Act, whilst the contribution renewable energies make to capacity used for electricity demand is likely to significantly lag behind that amount because of the high degree of fluctuating capacities. It remains an open question whether the assumed capacity of offshore wind power plants will in fact be expanded to the high amount of 20 GW by 2020 (as assumed by dena) and/or whether transport and distribution networks are expanded as a result. The necessary basic conditions for this to be achieved have not yet been created, making it more probable that the capacity of offshore wind power plants will be significantly lower in 2020 and will first reach its target level in 2030. In contrast, the rate of expansion of the use of photovoltaics is expected to continue, particularly given that the passed amendments to the Renewable Energy Sources Act will not allow for it to be held back from now on.

2.2.3.3 The building of new CHP plants

According to official statistics, the net electricity production from CHP amounted to approx. 80 TWh in Germany in 2006, 54 TWh of which was for the public supply and almost 26 TWh of industrial autogeneration. In order to quantify the CHP expansion target, it should be precisely defined:

- If **doubling CHP-based electricity** is defined based on data for 2006 rather than the target aimed for in the Federal CHP Act, net electricity production from CHP would have to increase by approx. 80 TWh to 160 TWh up to 2020. The 25% target would be met when the total net electricity production is no higher than 640 TWh (which still corresponds to an annual average increase of 0.5% compared to 2006). Since new CHP plants predominantly become economical when the duration of usage is 5,000 hours a year or more, an additional capacity of 16 GW can be expected under these conditions.
- However, if we assume – against the background of autonomous developments as well as energy and climate policy measures which have the effect of reducing consumption in terms of electricity demand – that net electricity production in 2020 is in the range of 540 to 560 TWh, the 25 % target would therefore already be met. When net CHP electricity production amounted to 135 to 140 TWh based on a growth of approx. 55 to 60 TWh, additional capacity of 11 to 12 GW can be expected.

In view of the discrepancies arising from unclear definition of the target and uncertainty about the electricity production level assumed for 2020, the target of 70 TWh of additional CHP-based electricity production (if the Federal CHP Act is fully effective) seems to be a feasible. This corresponds to an additional CHP capacity of 14 GW with a guaranteed capacity of approx. 11 GW. Also assuming that – supported by the Federal Renewable Energy Sources Act – additional CHP-based electricity production based on biogenic fuels is increased to

approx. 20 TWh up to 2020 (corresponding to a capacity of perhaps 4 GW or a good 3 GW of guaranteed capacity), approx. 50 TWh would have to be produced using fossil fuels (with a capacity of approx. 10 GW and a guaranteed capacity of 8 GW).

Conclusion: CHP can make a crucial contribution to meeting the future demand for electricity and capacity. However, doubt is rightly being cast on whether the Federal CHP Act, in its current version, can fully meet the target it has set. Many experts are expecting that the Act will most likely lead to a 7 GW expansion of CHP capacities.[2] Together with the additional support measures for biomass CHP plants laid down in the Renewable Energy Sources Act, an increase in CHP capacity of up to 10 GW in total (corresponding to approx. 7 GW guaranteed capacity) could occur, essentially easing concerns about electricity supply issues.

Excursus: Reducing CO_2 emissions on the basis of CHP plants

It is generally understood that the federal German government's target of doubling the share of CHP-based electricity production up to 2020 is linked to the intention of reducing CO_2 emissions and increasing energy productivity. As model calculations show, CHP actually contributes to saving primary energy in all plausible constellations. It is a different case with CO_2 abatement. The level of CO_2 abatement crucially depends on the specific parameters of the CHP plant in each case as well as the combination of energy carries used in separate electricity and heat production.

The energy carrier used in each case, the efficiency of combined and separate production and – especially in the case of CHP – the power-to-heat ratio are all crucial to the level of CO_2 emission reduction. As shown by the model calculations in Table 5 and retaining the assumptions used there, the CO_2 emissions of **a hard coal-fired CHP plant** (with a power-to-heat ratio of 0.7) can be reduced by just under 11 % compared to the separate electricity production in hard coal-fired condensation power plants and heat from heating systems that have a mix of ¾ natural gas and ¼ oil. The primary energy saving even amounts to almost 25% in this case. However, it should be noted that the CO_2 reduction crucially depends on the power-to-heat ratio in this example: When the assumptions otherwise remain unchanged, a CHP plant with a power-to-heat ratio of 0.45 would still lead to a primary energy saving (-14 %), but there would be no additional reduction of CO_2 emissions. With these comparisons it is decisive that the same energy carrier is used in the CHP plant and in the case of separate electricity production. In this way, the admittedly rather unrealistic comparison of a hard coal-fired CHP plant and a natural gas combined cycle condensation power plant using separate production would still result in a primary energy saving (if only a low one), but there would be no reduction in emissions.

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[2] See also the statements of experts at the hearing of the Committee on Economics and Technology of the German Bundestag on 7 April 2008. However, it should be noted that the version of the CHP Act that was passed in the end contains a significantly greater support than the draft version on which the hearing was based.

Table 5 Model calculations for determination of primary energy savings and CO_2 emission reduction by means of CHP plants

		Unit	CHP with hard coal		CHP with natural gas	
			Seperate production with …			
			Electricity: Hard coal	Electricity: Natural gas	Electricity: Natural gas	Electricity: Hard coal
			Heat: 75% natural gas/ 25% gasoil			
CHP plant	Electricity production	TWh	0.70	0.70	0.70	0.70
	Heat production	TWh	1.00	1.00	1.00	1.00
	CHP coefficient (power-to-heat ratio)	factor	0.70	0.70	0.70	0.70
	Efficiency factor CHP	%	83%	83%	87%	87%
	Total fuel input	TWh	2.05	2.05	1.95	1.95
		PJ	7.37	7.37	7.03	7.03
	CO_2 emissions	Mt CO_2	0.69	0.69	0.39	0.39
Seperate production of electricity and heat	Efficiency factor electricity production	%	45%	57%	57%	45%
	Efficiency factor heat production	%	88%	88%	88%	88%
	Fuel input electricity production	TWh	1.56	1.23	1.23	1.56
		PJ	5.60	4.42	4.42	5.60
	Fuel input heat production	TWh	1.14	1.14	1.14	1.14
		PJ	4.09	4.09	4.09	4.09
	Total fuel input	TWh	2.69	2.36	2.36	2.69
		PJ	9.69	8.51	8.51	9.69
	CO_2 emissions electricity	Mt CO_2	0.52	0.25	0.25	0.52
	CO_2 emissions heat		0.25	0.25	0.25	0.25
	Total CO_2 emissions		0.77	0.50	0.50	0.77
Savings of primary energy		**PJ**	**-17.10**	**-1.10**	**-1.50**	**-2.70**
		%	**-23.9%**	**-13.4%**	**-17.4%**	**-27.4%**
CO_2 mitigation		**Mt CO_2**	**-0.08**	**+0.19**	**-0.10**	**-0.37**
		%	**-10.7%**	**+38.5%**	**-20.4%**	**-48.7%**
Specific CO_2 emissions	Lignite	CO_2/TJ	111	111	111	111
	Hard coal		93	93	93	93
	Gasoil		74	74	74	74
	Natural gas		56	56	56	56
	75% natural gas/25% gasoil		60.5	60.5	60.5	60.5

Source: Authors' own estimates and calculations

A comparison of **combined production and separate production when natural gas is used in both cases** results in the finding that the primary energy savings are – in both absolute and relative terms – somewhat lower than in the comparison undertaken above, but the CO_2 emissions can be reduced even more strongly in this case when the conditions otherwise remain unchanged. This is even more so the case when a hard coal-fired condensation power plant is assumed for the separate electricity production.

In terms of emissions, the natural gas-based CHP plant not only has considerable advantages compared to separate electricity and heat production based on natural gas, but also compared to a hard coal-fired CHP plant. With this comparison, an emission reduction of over 40% would still result.

Conclusion: CHP plants can make a substantial contribution to energy saving and emissions reduction. The extent of these contributions crucially depends on the power-to-heat ratio of the CHP plants and the energy carrier used. In terms of emissions, natural gas has clear advantages over hard coal. If hard coal is going to be used for electricity production, it should be – wherever possible – in combined heat and power plants. Nevertheless, it should be pointed out that the emission reductions that can be achieved with hard coal-fired CHP plants compared to separate electricity and heat production (based on hard coal-fired power plants and natural gas condensing boilers) are – at approx. 10% – far removed from the reductions set out by climate policy. In all cases, both hard coal and natural gas condensation power plants would have a similar energy saving effect to the emission reduction attained via a CHP process.

2.2.3.4 Summary

The following conclusions can be drawn from the above considerations:

1. Projections for meeting the future electricity demand that are differentiated by electricity and capacity have to take into account and assess an array of factors. In doing so, there are varied degrees of freedom and room for interpretation, yet also substantial flexibility.
2. The analysis makes clear that it is necessary to carry out consistent electricity and capacity balances and to incorporate the available reserve capacities in the process. There are varied scopes of assessment and flexibility in the interpretation of data (especially with regard to capacity), although often only conservative use is made of them.
3. The phase-out of nuclear energy is a comparatively strong determinant, providing that the phase-out model for nuclear energy laid down in the Federal Atomic Energy Act of 2002 is followed. According to the Act, power plant capacities of almost 19 GW, a guaranteed capacity of 17 GW and electricity production amounting to 133 TWh have to be replaced by 2020.
4. The expansion of electricity production from renewable energies, which has been strongly supported politically, is also comparatively strongly set out. In addition, up to 2020 an electricity production of up to 100 TWh, a growth in capacity of 35 GW and a growth in guaranteed capacity of 9 GW can be expected.
5. There are strong political targets in the case of increasing the energy efficiency of electrical applications, but implementation measures – the contribution margins of which have a high uncertainty – have only been roughly planned. Potential contributions to the reduction of electricity consumption and to a reduced capacity demand are tentatively estimated at just below 40 TWh or 7 GW.
6. A similarly uncertain situation can be found in the politically supported expansion of CHP in Germany. If the expansion target of 25% by 2020 is met, the fossil CHP share of total production and capacity can be expected to be at least 50 TWh or approx. 10

GW. However, it cannot be ruled out that the Federal CHP Act will only bring about a 7 GW increase of fossil CHP.

7. The largest flexibility option for the medium term development of electricity supply concerns the shutdown sequence of fossil incumbent power plants. There are uncertainties and flexibility in the interpretation of data in this case too, spanning more than 20 GW.
8. Substantial power plant capacity is currently being implemented. However, at the same time coal-fired power plant projects are increasingly facing acceptance problems or rather it is hard to comprehend their compatibility with ambitious climate targets – also post-2020. Nevertheless, such a large number of power plant projects have been pushed ahead that substantial flexibility – even with a few emission-intensive power plant projects in mind – can also be assumed in this case.
9. In view of the individual considerations, it is difficult to appreciate the notion of an unavoidable gap in electricity production when a substantial amount of new fossil power plants (independently of CHP) are not built.
10. This assessment would need to be modified, however, if neither the Federal RES Act nor the Federal CHP Act meets with success, the electricity demand continues to grow in the future and current power plant capacities have to be taken out of operation for technical reasons. If these negative factors coincided, the “normal” reaction endogenous to the market would be a more or less pronounced increase in electricity prices with a corresponding impact on demand. At the same time, higher electricity prices would, of course, increase the economic efficiency of new power plants and substantially increase the incentive to build new fossil power plants. This means, of course, that there is a stronger incentive to build new coal-fired power plants, which still seems tenable from a climate policy perspective if done on a low scale.

Assessment of the development of an electricity production system capable of meeting demand is – at least with regard to the different production options – always ultimately a question of optimisation in the medium term with a time horizon of 10 to 15 years. With regard to the long term there are substantial uncertainties or differences in assessment in terms of the different developments, with the result that political interventions beyond those demanded by climate policy or infrastructural development require specific legitimisation. As a result it is scarcely feasible for the notion of supply gaps to be taken into account when it is based on rough analyses that use relative data and often depend greatly on the assessment approach.

2.2.3.5 Limiting greenhouse gas emissions in the long term and the subsequent effects on power plant expansion

When assessing power plant expansion in the years up to 2020, the long-term impacts need to be taken into account. Given that the operating lifetimes of new power plants is 40 years or more, these plants would continue to be part of the network until the middle of the century at least. This needs to be taken into consideration in the context of long-term emission reduction

targets, which amount to a reduction of greenhouse gas emissions by approx. 80% up to 2050 compared to 1990, at least for industrialised countries like Germany and within the EU.

For Germany this would mean that the greenhouse gas emissions in 2050 are only allowed to total approx. 245 million t CO_2-equivalent (1990: 1,228 million t CO_2-equivalent). If approximately the same reduction is assumed for non-CO_2 emissions, only 205 million t. CO_2 should be emitted in 2050 from all emission sources, i.e. from the residential sector, transport, commerce and industry and the energy sector. Compared to 2006, that is a reduction of 675 million t CO_2. If, for the sake of simplicity, a similarly high share compared to 2006 is assumed for the sector of public electricity and heat production (delineated according to national emission inventories), a permitted emission level of 80 million t CO_2 can still be assumed for 2050. Moreover, if restrictions in the case of emission reductions are taken into account in specific sectors (non-CO_2 emissions from animal husbandry, fertilisation, etc.), this level can fall to 50 million t CO_2.

In the following figure (Figure 4) model calculations show what power plant capacities or what fossil-based electricity production would still be just about compatible with such a target, under the given assumptions.

In the case of a baseload production, this would mean power plants of the following kind:

- Lignite-fired power plants with a capacity of 8 to 13 GW in the case of condensation electricity production **or** 9 to 14 GW in the case of CHP-based electricity production

or

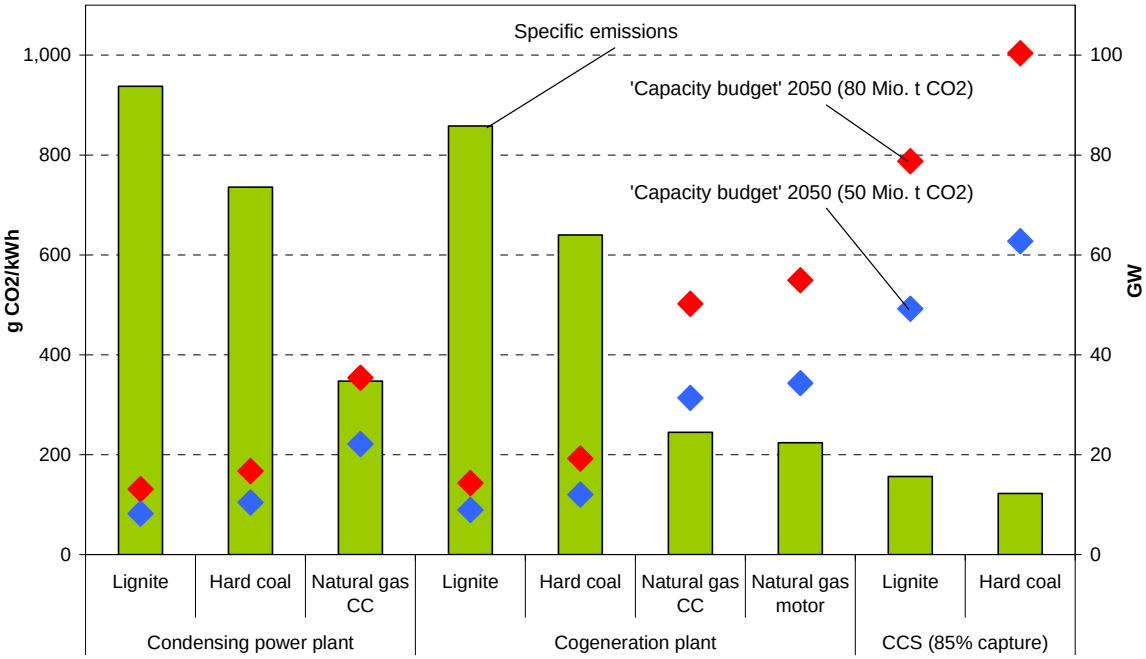
- Hard coal-fired power plants with a capacity of 10 to 17 GW in the case of condensation electricity production **or** 12 to 19 GW in the case of CHP-based electricity production

or

- Natural gas-fired power plants with a capacity of 22 to 35 GW in the case of condensation electricity production **or** 31 to 55 GW in the case of CHP-based electricity production.

Larger contributions of fossil-fired plants assumed in each case were only then compatible with climate protection targets when carbon capture and storage (CCS) is available – industrially as well as economically and ecologically – from 2020 onwards at the latest. The development of CCS technology has to be regarded as an issue of upmost urgency, not only from a national perspective but also for reasons of international resources policy.

Figure 4 Specific emissions and new incumbent fossil power plants permitted under climate protection restrictions in Germany up to 2050



Source: Authors' own calculations

Independently of this it is clear that by far the largest share of electricity production still needed in 2050 (the order of magnitude of which shall not be speculated within the scope of this short expert report) at any rate must – under the conditions of the continuing phase-out of nuclear energy – be based on renewable energies. Incidentally this is compatible with the 2007 pilot study "Strategy to expand renewable energies" ("Ausbaustrategie Erneuerbare Energien") followed by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, in accordance with which renewable energies could provide an electricity production amounting to approx. 430 TWh in 2050.

3 Assessing options and uncertainties as a multi-dimensional problem

3.1 Introduction

As the above analysis has shown, there are a variety of uncertainties on both the demand and supply side concerning not only existing but also new options of the electricity system. These uncertainties arise from the "inestimable" aspects of the energy industry and complex assessment issues concerning the energy and climate policy measures taken to date.

At the same time the German and European electricity production system has substantial flexibilities, which can compensate for a large share of the uncertainties at least in the short to medium term. It is therefore very unlikely that an "electricity gap" will open up in terms of interruptions brought about by insufficient supply.

Against this background the spectrum of developments concerning the modernisation and the – undoubtedly necessary – redesign of the (German and European) electricity system will have different impacts, in particular for three areas that are especially important to assessment of the possible courses of action:

- development of greenhouse gas emissions, in particular CO_2 emissions,
- development of prices for CO_2 emission allowances, and
- development of electricity prices (on the wholesale market), which partly depends in turn on the CO_2 allowance prices and the pass-through of CO_2 costs.

Of course alongside these three factors, there are also other aspects that are not insignificant (state subsidies for certain electricity production options or for increasing energy efficiency, infrastructure costs, etc.). Since the only issue of importance in the context of this short expert report is whether and what contributions could be made using the different production and demand options to meeting the electricity demand and what strategic courses of action could be taken, these other aspects shall not be considered in greater detail. Instead they should rather be analysed and assessed within the scope of a specific and, if necessary, politically defined portfolio of production and efficiency options or with a view to the concrete design of energy and climate policy instruments.

In terms of analyses and assessments for the three mentioned aspects – emissions, CO_2 emission allowance prices and electricity prices – it is necessary to continue distinguishing very clearly between the short- to medium-term perspective and the medium- to long-term perspective:

- The short- to medium-term time horizon is understood as being the period up to 2020. This period is characterised by the first interim targets set for the reduction of greenhouse gas emissions (30-40% for Germany or 20-30% for the EU, with 1990 serving as the base year in both cases), a widely defined regulatory framework for the EU Emissions Trading Scheme and an international climate regime in which industrialised countries in particular take on commitments and developing countries are already integrated in the carbon markets through the flexible mechanisms. The modernisation

process in the German electricity system is maintained above all by the politically determined phase-out of nuclear energy in Germany, the base levels for fuel, carbon and electricity for the given time horizon are probably still comparatively moderate.

- The medium- to long-term perspective is regarded as spanning from 2020 to 2050. This time period faces very challenging targets for the reduction of greenhouse gas emissions in industrialised countries like Germany (approx. 50% up to 2030 and 80-90% up to 2050). Only the rough outlines of the precise basic conditions for both the (EU) Emissions Trading Scheme and the international climate regime are currently visible. However, more binding commitments, also for developing countries and newly industrialised countries will be inescapable, particularly in the case of the international climate regime. This will have a substantial impact on international carbon markets in particular since developing countries and newly industrialised countries will then also be demanding emission avoidance options that are as low in cost as possible. In the period from 2020 to 2050, the German electricity system will largely have passed once through the modernisation cycle (compared to the current stage) with the result that power plants built after the turn of the century could still be operated if necessary. For fuel, carbon and electricity prices, significantly higher levels are assumed for this time period. In terms of modernisation technologies, substantial technological improvements as well as a fall in costs for renewable electricity production technologies as well as the commercial availability of carbon capture and storage (CCS) can be assumed for this period.

First of all, the impact on emission levels, CO_2 emission allowance prices, and electricity prices on the wholesale market stemming from the various development lines of the electricity system have to be differentiated for the different time horizons. Secondly, the uncertainties associated with the complex effects (regarding the energy industry as well as the concrete design that the climate regime will take) increase in principle over time. Thirdly, the impact has to also be seen in context, i.e. with the standard level becoming increasingly more challenging, above all in terms of climate policy. More ambitious targets of climate policy can increasingly have an impact on the economic basic conditions, which can ultimately further compensate for a share of the larger medium- to long-term uncertainties – if the necessary medium- and long-term ambitions of climate policy are accepted.

The potentially dramatic changes on the global energy markets have to continue to be kept in mind, along with their effects on the prices for fossil energies. In the process, substantial incentives are created for energy saving measures and measures to increase efficiency as well as for the use of increasingly competitive renewable energies.

3.2 The role played by the EU Emissions Trading Scheme

The Emissions Trading Scheme of the European Union (EU ETS) constituted a new and decisive basic condition for the future development of the electricity system. Of the many characteristics of the EU ETS, the following aspects should be highlighted:

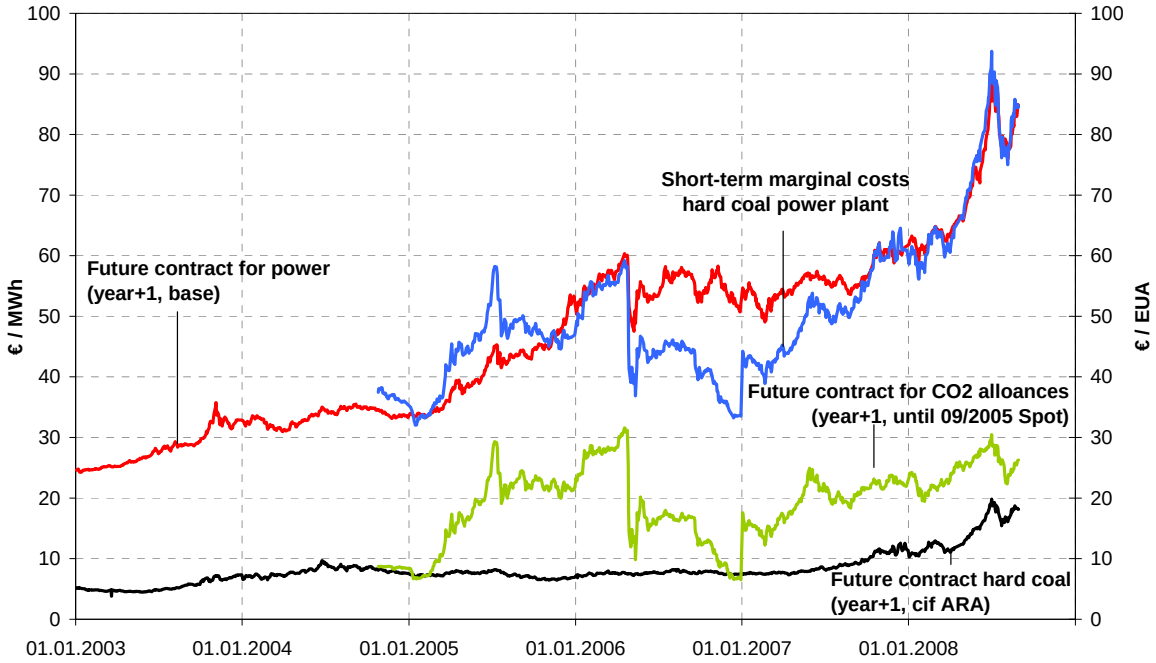
1. An emission target is set for Europe. Compliance with emission targets are guaranteed by means of the carbon price signal. But this also means that neither falling short of the emission target, nor overshooting it can be expected. If additional emission reduction options are exogenously introduced (i.e. conveyed through other support instruments), this leads to a lower carbon price, but not ultimately to a lower total emission level. The EU Emissions Trading Scheme is also a multi-phase scheme with new emission targets being set at more or less regular intervals. The emission target will be probably be set at the end of 2009 for the short and medium term. The EU targets for expanding the use of renewable energies has been incorporated as a basic rule in the suggested reduction targets for 2020. The emission target will be strengthened (according to the current suggestions of the European Commission on a fixed mechanism) if other countries also take on ambitious commitments as part of the international climate regime. For the medium to long term the emission targets have not yet been set to the same extent. Nevertheless, the EU Commission's proposal for the amendment to the Emissions Trading Directive published on 23 January 2008 clearly states that "in the longer term, by 2050, the European Council affirmed that developed countries should collectively reduce their emissions by 60-80 %…compared to 1990".
2. The Europe-wide emission target is made more flexible through the use of Certified Emission Reduction credits (CERs) of the flexible mechanisms, the Clean Development Mechanism and Joint Implementation. The extent of their usage is limited by current and proposed regulations. However, it is expected that the significance of the flexible credits for industrialised countries will fall considerably in the medium to long term if developing countries and newly industrialised countries (have to) increasingly take on their own reduction commitments.
3. The impact and economic efficiency of the EU ETS are based on the fact that the price of CO_2 emissions has to be taken into account in all decisions relating to the economic entities covered by the scheme. This carbon price signal can occur as a real cost magnitude (the purchasing of emission allowances) or via the opportunity costs (with the free allocation of emission allowances). However, an array of individual regulations in the EU ETS can distort or eliminate this carbon price signal (making free allocation dependent on production levels, free allocation for new power plants based on the emission level of the plants, etc.). This leads to efficiency losses and – under the given targets – to higher carbon prices in the future.

Alongside its internal interactions, the impact of the Emissions Trading Scheme on wholesale electricity markets also needs to be taken into account, provided that such markets are competitive and lack distinct monopolistic or oligopolistic structures.

On a competitive electricity market with marginal cost pricing, the basic electricity price will settle at a level corresponding to the short-term marginal costs of the marginal electricity production unit. The short-term marginal costs for electricity production are above all made up of the fuel costs and the costs for CO_2 (for purchasing the emission allowances needed as well as the opportunity costs of emission allowances obtained via free allocation). In Figure 5 the historical cost trends for hard coal, CO_2 emission allowances as well as baseload electricity

supply are summarised, for supply in the year ahead (by referring to future contracts, basic interactions can be made clear and the more temporary market effects can be removed).

Figure 5 Hard coal, electricity, and carbon prices (Year Ahead Futures) and the short-term marginal costs of electricity production, 2003-2008



Sources: EEX, PointCarbon, McCloskey, EZB, authors' own calculations

By way of example, these price developments are compared with the short-term marginal costs of a hard coal-fired power plant which could at some point constitute the marginal electricity production plant for the German market for substantial periods of time. The comparison shows that (with the exception of the collapse of the carbon prices in April/May 2006) the short-term marginal costs of this hard coal power plant explain the electricity price level for baseload supply relatively well. The CO_2 costs are therefore a basic factor in explaining the development of the basic electricity price level on the wholesale level.

The complex mechanisms within the Emissions Trading Scheme and in terms of the interactions of carbon and electricity markets are a key basic condition for assessment of the different development and political courses of action available – both for the short to medium term and for the medium to long term.

3.3 Quantitative electricity price effects

The following analysis will comment on the qualitative development of carbon and electricity prices. A quantitative assessment would necessitate comprehensive model analyses along

with a plethora of sensitivity calculations for the different basic parameters. Such an assessment cannot and should not be delivered within the scope of a short expert analysis.

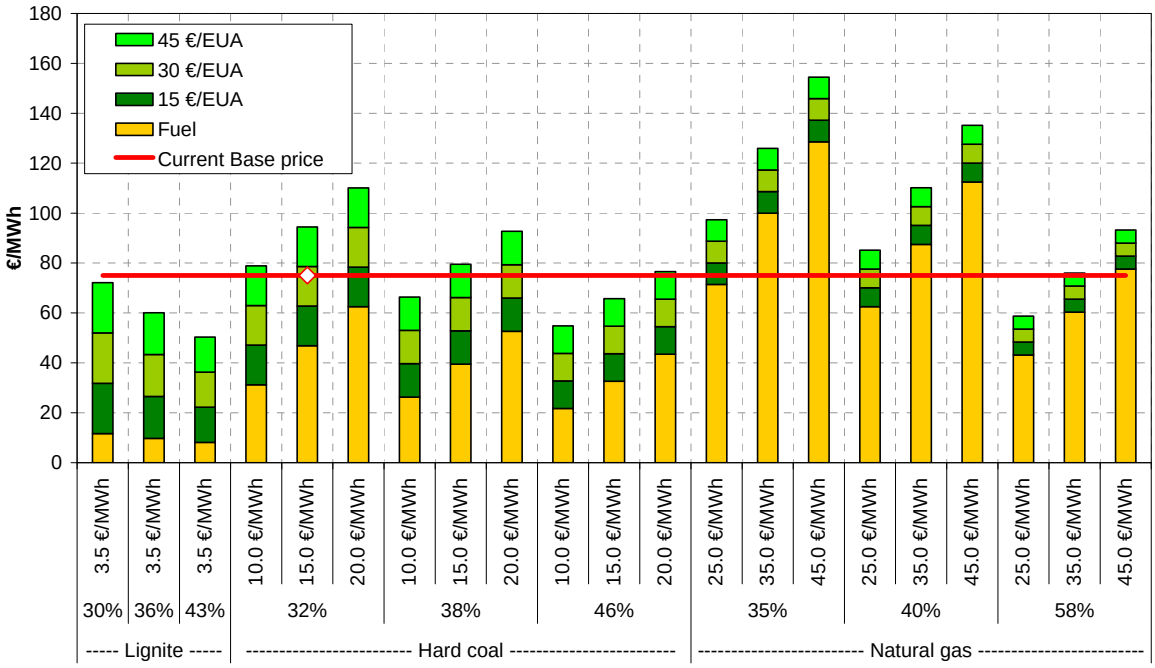
But to be able to perform an exploratory assessment, an array of examples of short-term marginal costs for different electricity production options – which either are or can become relevant to pricing in German or continental European markets – are shown in

Figure 6. In the figure, the following alternatives are summarised for representative power plants of fossil electricity production with different electricity production efficiencies:

- The average levels for fuel and CO_2 costs represent current levels (as of the beginning of June 2008). CO_2 costs of almost 30 €/EUA as well as costs (at plant gate) of 15 €/MWh for hard coal and approx. 35 €/MWh for natural gas are typical here. For lignite a constant level of approx. 3.5 €/MWh is assumed.
- The lower levels show the price levels which could be regarded as representative for the beginning of 2005. At that time certificate prices of approx. 15 €/EUA were accompanied by hard coal prices of approx. 10 €/MWh and natural gas prices of approx. 25 €/MWh. The fuel prices for lignite were not changed.
- The upper levels of the CO_2 and fuel costs are hypothetical; they are the levels that could arise if current trends continue.

A comparison of short-term marginal costs for the different electricity production options with the current baseload prices on the wholesale market shows that the electricity price level is currently primarily represented by an older hard coal power plant (with a low efficiency of only 32%). In the case of both old and new lignite power plants the marginal costs of the current fuel and carbon prices are substantially below the current price levels on the energy exchange. Under the above-mentioned general conditions newer hard coal power plants have much too low marginal costs and old natural gas-fired power plants much too high (short-term) marginal costs for them to be able to significantly explain the current electricity prices. Only the marginal costs of very modern natural gas-fired power plants have short-term marginal costs that are very close to the current price levels for baseload supply.

Figure 6 Short-term marginal costs of different fossil electricity production options for the continental European market



Sources: EEX, PointCarbon, McCloskey, EZB, authors' own calculations

If no changes are assumed for fuel and carbon prices, it follows that the complete exclusion of the current price-setting power plants by (somewhat) more modern power plants (represented here by hard coal-fired power plants of 32% and 38%) can have a maximum electricity price effect of 5 to 10 €/MWh. If, instead of having the old hard coal-fired power plants as the price-setting plants, natural gas combined cycle power plants built in recent years are used, the electricity price effect of the removal of the old hard coal power plants from operation would be significantly below 5 €/MWh. It is assumed for the next one or two decades that the price levels cannot be set by modern hard coal- and lignite-fired power plants and could therefore fall substantially.

The overview also shows that the fall in electricity price effects through the modernisation of the power plant fleet are significantly below the orders of magnitude that could arise from increases in fuel and carbon prices compared to current levels.

It can be seen from the model calculations that the level of electricity prices is determined above all in the area of the conversion of hard coal and natural gas into electricity (i.e. modernisations in this area and the relevant fuel and carbon prices). Although the impact of CO_2 costs clearly dominates the short-term marginal costs in terms of the conversion of lignite into electricity, the low level of fuel costs comes to bear overall.

With regard to future electricity price developments on the wholesale market it can be inferred from the calculations shown above that should the current energy and carbon price trends continue or develop further, price levels in the region of 80 to 100 €/MWh are to be

expected rather than of 50 to 60 €/MWh even in the case of extensive modernisation of the German electricity production system. This order of magnitude of the expected price levels should be borne in mind during the classification undertaken in the following analysis.

3.4 Assessing possible strategies

In the context of the stated uncertainties and flexibilities described above, the different possible courses of action can be developed into strategies. Strategies are understood to be basic action approaches which can (initially) be analysed independently of the choice of concrete political instrument.

Such strategic action as this is above all necessary when – against the background of the following considerations – the set targets are not being met using the measures taken to date. In this case the basic strategies described below come into consideration and can be pursued alone or in combination. Strategic courses of action other than the ones discussed here and which set the basic conditions completely differently (e.g. with regard to whether the EU Emissions Trading Scheme is continued, an electricity market model based on competition and marginal cost pricing is applied and the phase-out of nuclear energy is continued) are also possible. Therefore an important selection criterion for the strategic courses of action discussed here was that they feature prominently in the current political discussion.

1. *No further interventions: Focus on the (self-) regulatory mechanism of the liberalised electricity market and the flexibility of the existing power plant fleet*

   If the energy and climate policy measures taken up to now are not sufficient to gain acceptance for production and demand options requiring political support because they will otherwise not find acceptance in the environment of free competition, this strategy would then be geared to the flexible retroactivity of the German and European CO_2 and electricity markets alone. It is assumed that rising carbon and electricity prices provide sufficient incentives for the necessary measures on the supply and demand side.

   At least in the short and medium term the existing electricity system contains the necessary flexibility options which could bridge the period of time in which necessary adaptations processes take place. In the short and medium term this would not have any impact on the achievable emission levels in the overall system since the emission targets have been set for at least until 2020 within the framework of the EU ETS, which can also be met externally[3], using emission abatement measures in other sectors of the EU ETS or by purchasing CERs from JI and the CDM. This kind of integration of climate policy is far less guaranteed in the longer term since practical experience shows that when emission

[3] As long as such credits (CERs) are available on the supply side or can be used within the framework of the EU ETS. This depends above all on the permitted level of use of such credits within the EU ETS, which differs for the various development options of the EU ETS.

levels are reached quickly, they make up a key basic condition for the determination of future emission reduction targets.

Emission reduction initiated outside of the Emissions Trading Scheme and to a lesser degree (using other measures such as the Federal Renewable Energy Sources Act, Federal CHP Act or energy-saving measures) will lead to higher prices for emission allowances in the short to medium term. If it is assumed for the medium to long term time horizon that the desired targets are not weakened in this case, there will also be greater increases in carbon prices for this time horizon as well.

With the trend towards higher carbon prices, the electricity prices on the wholesale markets also increase. The extended operation of older, price-setting power plants likewise increases – if probably to a much lesser extent – the electricity price levels on the wholesale level.

Rising wholesale prices also increase the attractiveness of market-driven new investments over time. The higher the CO_2-induced share of the price increase, the more attractive become power plant options with low CO_2 emission levels.

In terms of the retail prices, growing wholesale prices will be complemented by the lower costs of the CHP Act and RES Act allocation mechanisms. If lower sums are made available through these allocation mechanisms, retail prices fall. The same applies in the case of budget-funded measures, which have an impact on the necessary tax revenue but not on the electricity prices.

The lack of merit-order effects still ultimately tends to lead to rising electricity prices when the target is not met in the case of options that are capable of significantly triggering such effects.[4]

However, with this strategy approach the question arises – at the latest in the medium to long term – as to whether the backstop technologies (that are undoubtedly needed so that ambitious climate protection targets are met) and the necessary increases in efficiency can be made available in due time if the interim target is not met and without readjustment of the supporting measures.

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[4] If politically supported production options or a decreasing demand indirectly push out the power plants that have set the prices up to now in favour of plants with lower short-term marginal costs, it indirectly reduces the wholesale price (merit-order effect). However, if renewable energies experience stronger market penetration, the necessary expansion of flexible power plant capacities in the medium to long term can also lead to power plants with higher short-term marginal costs (e.g. gas-fired power plants) increasingly contribute to pricing, thereby bringing about merit-order effects which tend to have the effect of increasing prices.

2. *Readjustment if the target is not being met: Updating political measures relating to energy efficiency in electricity applications (with regard to electricity and capacity), of CHP as well as renewable energies in electricity production*

   Such a strategy approach can be considered when it does not seem sufficiently guaranteed that the set targets for expansion of the use of renewable energies, CHP or on the demand side do not seem to be achievable using the instruments deployed to date.

   In the short to medium term, such readjustment as this does not lead to a change in emission levels, at least in the overall system since the emission target of the EU ETS is fixed up to 2020. The missing emission reductions of these areas would be compensated either by other abatement options within the EU ETS or by purchasing CERs (JI/CDM)[5]; an appropriate readjustment would make these market-driven compensations superfluous.

   If the targets for expansion of the use of renewable energies and for increasing energy efficiency were taken into account during determination of the targets for the EU ETS[6], failure to meet the targets would lead to rising carbon prices since more expensive abatement options would have to replace the very low-cost abatement options (from the perspective of the EU ETS) made available through state support. If the long-term expansion of electricity production from renewable energies and CHP and tapping efficiency potentials are to be significant in meeting emission reduction targets, failure to meet the targets leads automatically – also in the long term – to higher carbon prices, if the future targets of the Emissions Trading Scheme are not made less ambitious.

   Rising carbon prices lead automatically to higher wholesale electricity prices on the single European market for electricity. For the final electricity customers privileged within the framework of support instruments for renewable energies and CHP, i.e. wholly or predominantly exempt from the relevant cost allocation, such changes in electricity prices are of course indirectly reflected in the retail prices. This is even more so the case when the merit-order effects also come into effect in the medium term through the specific support of renewable energies and CHP (see above).

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[5] However, if these options are not effective in the medium to long term, a “gap” then arises in terms of greenhouse gas emission reductions, especially when the missing reductions are compensated by the purchasing of external credits (CERs) and future emission targets are based upon the emission levels actually achieved in the time period (such updating is highly problematic from an economic perspective, but is increasingly being applied in the real EU ETS and in the international negotiation process).

[6] The EU expansion target for renewable energies has explicitly been taken into consideration in the proposals of the European Commission on the allocation of emission targets to sectors covered and not covered by emissions trading.

3. *Support for investment in fossil power plants: Supporting of fossil power plant projects that face difficulties in terms of economic feasibility in the framework of current energy and climate policy.*

   Such political support is under discussion, above all in view of three mechanisms:

   - Continuing free allocation with emission allowances for new power plants – for Germany this primarily means fuel-specific benchmarks for new power plants (i.e. the share of free allocation increases with the emission level of the plant). This is the equivalent of technology-specific subsidisation of new power plants.
   - Competition models for capacity investments are under discussion, most notably for the USA, in light of the apparent lack of investment incentives within the scope of electricity markets based on marginal costs. In this way, sufficient incentives for investments shall be provided. However, these discussions have only been rudimentarily held for Europe.
   - Finally, in the field of "soft" measures, the implementation of acceptance-raising measures for new fossil (condensation) power plants is under discussion – and put into practice.

   In terms of the short- to medium-term effects of such a strategy on the emission levels, the following aspects need to be considered:

   - If old power plants are shut down and new emission-intensive (coal-fired) power plants are built in return, emission levels fall accordingly (generally in the region of 20-30% for each plant).
   - If such shutdowns do not occur or not to the same extent, these emission reduction effects do not apply or fall accordingly. Substantial power plant capacities whose marginal costs (in terms of the current or expected fuel and carbon prices) are higher than the old coal-fired power plants in Germany (the emission levels of which are significantly lower) are operated on the European electricity market. On the basis of being pushed out of the market, emissions would not be reduced overall in Germany or Europe.

   Although emission reductions seem ostensibly logical when replacing old power plants with new ones, the specific trend of emissions in the context of market interactions in the European electricity market cannot be estimated with any sort of certainty as long as the putting into operation of new power plants is not bindingly carried out in conjunction with the shutdown of old power plants.

   In terms of the emission levels, a fundamental problem arises when emission-intensive power plant projects are complemented in the medium to long term by the building of power plants with substantial operating lifetimes and on the basis of whose cost structure (comparatively low fuel costs) a high load factor and therefore high emissions can be expected in the long term.

If these emission contributions are not compatible with long-term emission reduction targets in the region of 80% (compared to 1990 emission levels), future energy and climate policy action will face a problem:

- For a hard coal-fired power plant to be pushed out of the market on the basis of short-term marginal costs alone when high fuel prices are expected (for hard coal and natural gas), high carbon prices (up to 100 €/EUA) are necessary, with the corresponding impact on electricity price levels.
- The same is true for the market-driven retrofitting of such power plants with technologies for carbon capture and the storage of CO_2 in geological formations (CCS). Based on current projections substantially higher costs are expected for the retrofitting of existing power plants with CCS technology (investments, energy penalty for CO_2 capture, etc.) than for the building of new such plants, meaning that retrofitting will also only be probable in the case of very high CO_2 costs.
- Introducing a legal retrofitting commitment for CCS technology faces a three-fold problem:
    - Retrofitting would probably have to take place in the write-off period, which is problematic in economic terms, especially in a competitive market.
    - In the past there have been similar retrofit commitments (e.g. for flue gas treatment equipment) although these are perhaps only partly comparable given the cost effects. In the monopoly market of those days, it was possible to pass on the relevant costs to the customers without greater adverse effects on the competitive position. Since conditions have changed, this is no longer possible.
    - Past examples of retrofit commitments were also supported by extensive use of special tax provisions (special capital allowances, etc.). Whether such compensations could be realised in a similar or different way under the current general conditions is questionable.

The impacts of this strategy on the development of the emission allowance price needs to be distinguished:

- If the politically supported building of new fossil power plants does not lead to the more emission-intensive plants being taken out of operation, it tends to result in rising emission allowance prices, at least in the short and medium term. Otherwise there would tend to be a downturn in emission allowance prices.
- If political support results in a distortion of the carbon price signal (e.g. via a free and fuel-specific allocation to new power plants), it reduces the efficiency of the overall scheme and thereby also tends to increase carbon prices, at least in the medium to long term.
- If subsidisation of new power plants does not differentiate between the various technologies and fuels, market distortion is confined to demand elasticity. If high elasticity of electricity demand is assumed for the (wholesale) electricity price, subsidisation of new power plants has the effect of significantly increasing the carbon price. If

lower price elasticity is assumed, there are only low effects for the price of emission allowances.

Alongside the electricity price effects of new prices for emission allowances, the specific trend of which cannot be estimated with certainty, there are price effects, especially from the other short-term marginal costs of price-setting power plants. If it is assumed that, given direct or indirect support of new power plants, only those power plants are built whose short-term marginal costs are under those of other price-setting plants (otherwise no contribution margins would be generated), a fuel-dependent trend towards lower electricity prices results from the expected higher efficiency of new power plants. This trend would only then be reversed when the specific fuel costs of the new power plants are greater than those of the price-setting old power plants but the CO_2 and fuel costs of new power plants are lower than for the old power plant. In this case, a fall in electricity prices would definitely result.

4. *Moratorium on coal: No or only periodic building of new coal-fired power plants*

Currently the building of new coal-fired power plants is deliberately not being pursued, both on a strategic level – i.e. disassociated from the necessary political instruments – and in the case of specific power plant projects. With this approach local objections (local immission loads, cooling water inflow, urban development issues and infrastructural issues, etc.) are accompanied by concerns about the compatibility of these power plant projects with an ambitious long-term climate protection strategy. From the different lines of discussion pooled under this "moratorium on coal" strategy, two basic approaches can be distinguished:

- complete and final abandonment of building coal-fired power plants ("coal phase-out"), and
- complete abandonment of building coal-fired power plants until new power plants can be fitted with CCS technology (CO_2 minimum standards) and secure storage sites are made available.

In terms of CO_2 emissions, carbon prices and the – at least partly associated – electricity price effects, the isolated effects of this strategy correspond to those of the first alternative mentioned above in the short to medium term if there are no economic or other reasons for not building new power plants:

- The level of CO_2 emissions does not change overall because of restrictions stemming from the EU Emissions Trading Scheme;
- the carbon prices will tend to rise overall; and
- the electricity prices will tend to rise, above all due to the rising carbon price, but also because old power plants are not being replaced with newly built plants.

In the medium to long term there are effects which depend on other developments:

- If the (provisional) abandonment of the building of new power plants (without CCS technology) up to 2020 can be compensated post-2020 by the extensive availability of further production options with low CO_2 emissions and (then) lower costs (renewable energies, power plants with CCS technology, natural gas-fired power plants – if price levels for natural gas are then lower), there will be:
  - more freedom in setting the new emission trading cap, i.e. downward trend in CO_2 emission levels;
  - a generally stabilised carbon price level; and
  - at the same time stabilised levels for wholesale electricity prices.
- If post-2020 further production options (e.g. because of the abandonment or exclusion of CCS) are not readily available, there will be:
  - substantial restrictions in the political environment in terms of the determination of the emission trading cap, i.e. an upward trend in CO_2 emission levels;
  - a further (strong) upward trend in terms of the carbon price level (in the case of comparable emission targets) – until the remaining electricity production options become available both in terms of quantity and price; and
  - at the same time a continued (strong) upward trend in electricity price levels.

The effects of a moratorium on coal would become relevant for the medium to long term time horizon. However, in this time period they heavily rely on progress being made in the development of further (or more economical) production options or on the scope of the politically "sanctioned" portfolio.

5. *Accelerated shutdown of old and particularly emission-intensive power plants through the political framework*

Existing power plants and plants that are still economically operable on the market under corresponding general conditions for fuel prices and emission allowance costs can be forced into shutdown by political interventions. For example:

- by setting minimum efficiency standards or CO_2 emission limits, and
- by placing retroactive restrictions on the operating lifetimes of power plants (through new approval procedures).

Irrespective of how compatible such a strategy is with current emissions trading (this is of course also the case for the strategies "Support for investment in fossil power plants" and "Moratorium on coal"), it results in the following implications in the short and medium term:

- Total level of CO_2 emissions would remain unchanged within the framework of the EU Emissions Trading Scheme;
- Carbon prices would initially fall, the net development would however depend on investments induced in the electricity market; and

- Electricity prices would initially fall as a result of the carbon price signals; however, if there is no new power plants are built on the basis of the electricity production options, electricity prices would rise due to scarce capacity.

The specific trend of effects on carbon and electricity prices in the short to medium term cannot therefore be estimated with certainty. However, problematic constellations could also emerge in the long term: a strong downward trend in carbon prices in conjunction with high scarcity signals in the electricity market would lead to strong incentives to invest in electricity production technologies that tend to be more emission-intensive. Precisely because of this, the following medium- to long-term effects arise:

- The specific trend of the total level of CO_2 emissions cannot be confidently estimated when it is assumed that carbon price signals in particular and the existing capital stock have an impact on the determination of emission targets in the real world;
- The development of carbon price signals remains uncertain; in the case of a sharp increase in investments in emission-intensive technologies against the background of the above-mentioned mechanisms, carbon prices could rise in the medium to long term;
- Due to the same mechanisms the specific trend of electricity price development cannot be estimated with certainty, but a large spectrum of different developments can be expected.

In particular for the strategy discussed here it should be borne in mind that the short- to medium-term effects are the product of complex interactions on the electricity and carbon markets and also depend on other basic conditions, above all concerning new investments. Estimating the specific trend of these conditions is scarcely possible.

In summarising the strategies discussed here it becomes clear that isolated discussion of the different possible courses of action is not reasonably possible. Pursuing the strategy “Accelerated shutdown of old power plants” in conjunction with “Support for investment in fossil power plants” can lead to totally different results than would be the case when pursuing this strategy in conjunction with a course of action based on “Self-regulation of the electricity and carbon markets” alone.

Interactions on the electricity and carbon markets are and will remain highly complex and can often bring about the reverse of the desired effects of isolated strategies. This makes it necessary for an array of uncertainties and dilemmas to be considered.

3.5 Dealing with uncertainties and dilemmas

In the relevant (political) discussions on the different strategic courses of action or their individual elements, the consequences of the strategies are often considered too one-sidedly or are simplified. In this way explicit support of new investments does not necessarily lead – neither in the short to medium term, nor in the medium to long term – to lower CO_2 emissions or

lower carbon and electricity prices. A similar situation arises when, for instance, no building of new coal-fired power plants is undertaken, either indefinitely or for a definite period of time.

If the different courses of action and basic conditions are systematically assessed, the following key aspects need to be taken into account in the uncertainty assessment:

- Is it assumed that the electricity production options with low emissions and competitive costs or the available electricity production potential of these production options increase in the future to a greater extent than at present or than is currently expected (renewable energies, CCS, etc.)?
- Is it assumed that the determination of future emission targets in the EU Emissions Trading Scheme will be more strongly geared to the requirements of climate policy and less towards the associated economic issues (carbon price level that has been reached, abatement potentials of the existing capital stock, etc.)?
- Is it assumed that higher carbon prices in the short and medium term have a significant effect on the available potential of less emission-intensive electricity production options in the future?
- Is it assumed that in the short to medium term as well as in the medium to long-term climate policy instruments beyond the EU Emissions Trading Scheme will or have to play – for many different reasons – an important role?

Depending on these key uncertainties, an array of dilemmas arises for climate and energy policy:

- Is it acceptable to forego investments which lead to rather limited or partly uncertain emission reductions if such investments result in significantly more efforts being made to meet very ambitious climate protection targets (but at significantly higher costs) in the medium and long term?
- Does the gearing of energy and climate policy interventions towards lowering carbon and electricity prices in the short and medium term then lead to a particularly strong increase in carbon and electricity prices in the medium to long term?
- Is the restriction to a minimum of climate and energy policy instruments that complement the EU Emissions Trading Scheme or the competitive electricity market useful or will these complementary instruments become key elements in the necessary redesign of the electricity production system for the medium to long term?

Solving these dilemmas is by no means a trivial exercise; indeed it can be only achieved in an iterative and long-term process. Nevertheless, several conclusions – which can be regarded as robust in terms of the uncertainties and dilemmas described above – can be drawn from the above considerations:

1. If it is assumed that the options currently supported outside of the EU Emissions Trading Scheme on the supply and demand side (renewable energies, CHP, electricity saving) are indispensable for medium- to long-term development (and were also explic-

itly considered in the determination of emission targets in the EU Emissions Trading Scheme), the relevant political measures should be readjusted when it is foreseen that the targets will not be met.

2. Subsidisation of conventional power plants (e.g. via free allocation in the EU Emissions Trading Scheme) is not a useful option, especially with a view to the medium to long term. This is especially the case when the subsidy mechanisms are not designed to be technology- and fuel-neutral, thereby fundamentally distorting the impact of other political instruments (such as the EU Emissions Trading Scheme). If measures to expedite the shutdown of old power plants directly or indirectly necessitate the support of new power plants, the strategy should also be regarded as problematic.
3. An approach which draws upon the moratorium on coal strategy could only prove useful when the postponement of investment decisions is restricted to the short to medium term and substantial efforts are made to make further options for the electricity system available in the medium to long term. The question of CCS technology and renewable electricity production technologies – which are still far from making significant contributions to the electricity supply or economic operation – as well as increasing electricity efficiency are of particular importance in this context.
4. In any case the key aspects for the necessary discussions and assessments are the medium- to long-term effects of the different energy and climate policy intervention strategies. Discussions concerning the post-2020 situation often tend to focus on contraproductive courses of action because the proposed courses of action are too short-term.
5. In the light of the large uncertainties and substantial complexity of different interactions, market-based exploratory processes (both on the electricity market and on the carbon market) should be given high priority. At the same time, it should be borne in mind in the discussion that the previous time horizons for the (predominantly short-term) market-based optimisation processes differ considerably from the time horizons in the case of measures that are necessary in the long term. Expansion of the (period-based) optimisation framework of the EU Emissions Trading Scheme is therefore of pivotal importance.