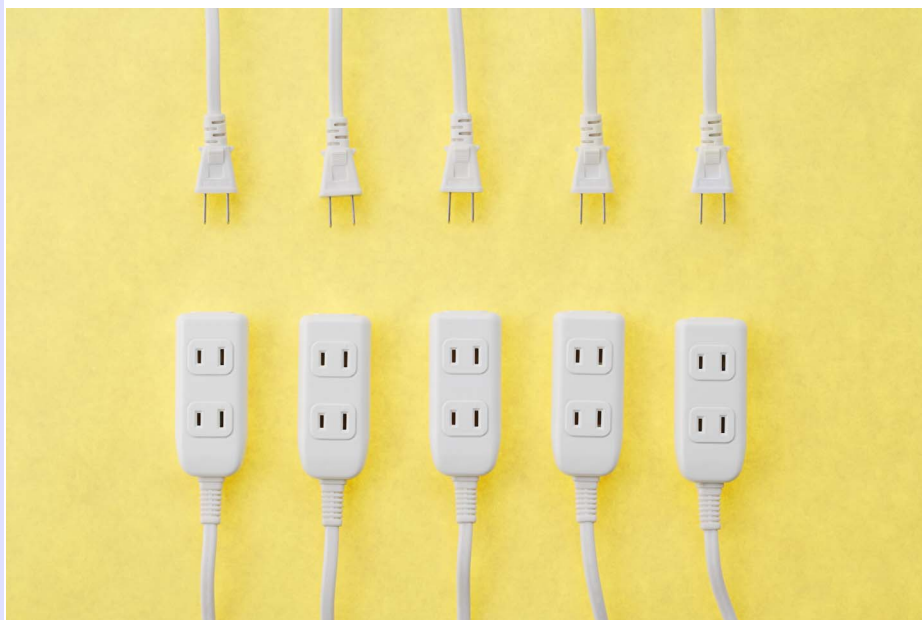




17 November 2010

German Power

The Time Is Out of Joint



Special Report

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Capacity closures over 2011-14 key to restoring sustainable margins

With clean spreads at three-year-lows and full EUA auctioning to kick in from 2013, we think that many of Germany's older coal and gas-fired plants will not be able to cover their fixed costs after 2012. Moreover, although forward power prices remain well below new-entrant levels over 2010-14, we estimate that 39GW of new capacity (12GW of fossil-fuel and 27GW of renewables) will nonetheless come onstream over this period. We conclude that capacity closures of older coal and gas plant in excess of 20GW will be needed by 2014/15 to restore sustainable margins to the remaining coal and gas-fired plant on the system.



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Capacity closures over 2011-14 are the key to restoring sustainable margins

With clean spreads at three-year-lows and full EUA auctioning from 2013, we think that many of Germany's older coal and gas-fired plants will not be able to cover their fixed costs after 2012. Moreover, although forward power prices remain well below new-entrant levels over 2010-14, we estimate that 39GW of new capacity (12GW of fossil-fuel and 27GW of renewables) will nonetheless come onstream over this period. We conclude that fossil-fuel capacity closures in excess of 20GW will be needed by 2014-15 to restore sustainable margins for coal and gas plant.

Near-term capacity surplus, and demand recovery set to slow

With our base-case scenario now assuming that Germany's nuclear plant will receive average lifetime extensions of 12 years, capacity margins today look more comfortable than at any time in the last five years, while the recovery in demand seen so far in 2010 looks set to slow into 2011 (we assume a rebound of 3.5% in 2010, and then a CAGR of 0.75% over 2011-14).

The total capacity on the system is actually set to increase over 2011-14

Although the forward baseload curve and clean spreads currently indicate that prices will remain well below fossil-fuel new-entrant levels for the foreseeable future, a material amount of new capacity will nonetheless come onstream by 2014 because (i) there is already 12-13GW of fossil-fuel capacity under construction, and (ii) the generous subsidies for renewables mean that wind, solar, and bio-mass capacity will carry on rising aggressively over the next few years irrespective of what happens to wholesale prices.

But we assume a net reduction in fossil-fuel capacity of 5.5GW over 2011-14

Based on generic operating lifetimes of 45 years for coal and lignite stations, 30 years for CCGTs and 40 years for other fossil-fuel plant, we see potential for 17.6GW of closures by the end of 2014, against which we expect 12.1GW of new fossil-fuel capacity to come on-stream over the period.

The outlook over 2011-14: healthy for lignite, but bleak for coal and gas

Taking our assumptions on demand, changes in the capacity mix over 2011-14, and the outlook for commodity prices over this period, our base-case scenario for power and spreads sees slightly higher baseload prices over 2011-12 than the current forward curve, with clean dark spreads that are actually worse than the market is currently projecting, but clean spark spreads that are slightly better. Over 2013-14 our model projects baseload prices very much in line with the forward curve, with improving dark spreads but appreciably weaker spark spreads. Our stark conclusion is that with full EUA auctioning from 2013, lignite generators will continue to make very healthy margins beyond 2012 but that many older, less efficient coal and gas plants will not be able to cover their fixed operating costs once they have to pay for 100% of their EUAs.

Decision time for incumbent coal and gas-fired generators

We think full EUA auctioning from 2013 will force coal and gas-fired generators to think about higher levels of closures over 2011-14 than the 17.6GW assumed in our model. We estimate that an extra 4-5GW of closures above and beyond our base-case scenario – i.e. net fossil-fuel closures over the period of c.10GW – would bring the de-rated capacity margin down below 10% by the winter of 2014/15, and to below 15% already by the winter of 2013-14 (or possibly slightly sooner if demand from neighbouring markets over the period is higher than we are assuming). In turn, this would in our view bring prices and spreads back towards sustainable levels for remaining coal and gas plant by 2014/15. It is therefore decision time for the owners of Germany's older coal and gas-fired plant.

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Executive Summary

Our analysis in this report shows that the outlook for Germany's incumbent hard-coal and gas-fired generators over 2011-14 is bleak. With capacity margins currently very comfortable and the outlook for demand still muted, the forward curves for baseload power out to 2014 are well below new-entrant levels, and with clean spreads at three-year-lows and the prospect of full EUA auctioning from 2013, we think that many older, less efficient coal and gas plants will not be able to cover their fixed operating costs beyond 2012.

Moreover, although the forward baseload curve currently indicates that prices will remain well below fossil-fuel new-entrant levels for the foreseeable future, a material amount of new capacity will nonetheless come onstream by 2014 because (i) there is already 13.2GW of fossil-fuel capacity under construction, and (ii) the generous subsidies for renewables mean that wind, solar, and bio-mass capacity will carry on rising aggressively over the next few years irrespective of what happens to wholesale prices.

Worse still for incumbent fossil-fuel generators, most of this new renewable capacity will produce zero-marginal cost electricity once it is built, and will therefore displace fossil-fuel output in the merit order. This means that fossil-fuel plants in general – and incumbent coal and gas-fired generators in particular – will likely be running fewer hours with each year that passes while also receiving lower average baseload prices in the hours that they do run owing to the impact more low or zero-cost output will have on the price-duration curve.

Against this background we think that the move to full EUA auctioning from 2013 will force the owners of coal and gas-fired plant to think about shutting down more of their old capacity than they ordinarily would do based purely on standard operating lives, and the key here will be the responses of two major sets of players in the German power market: (i) the major generators/integrated utilities, and (ii) the 'long tail' in the German generation system.

If the major generators (the integrated utilities) are unwilling to cross-subsidize peaking stations from the cashflows of their lignite and nuclear output then a more rapid attrition of capacity can be expected from 2013 than we have assumed in our base-case scenario.

Just as important to the overall balance of the system, however, could be the behavior of the 'long tail' in the German generation system, i.e. the smaller units operated by regional companies, the combined heat and power capacity of the industrial users, and the co-gen stations of the district-heating operators.

If these operators cross-subsidize generation from their other revenues then over-capacity may be a long-term systemic problem. However, if they prove less able to absorb lost generation revenues than the integrated utilities, then the tail could dwindle rapidly, and capacity margins reach tighter levels more quickly than our base-case scenario assumes.

Overall, the conclusion from our modeling is that while the 17.6GW of fossil-fuel closures we have assumed in our base-case scenario – or 5.5GW of net fossil-fuel closures after adjusting for assumed new build of 12GW -- will not be enough to enable much of Germany's coal and gas-fired capacity to cover its fixed costs over 2013-14, an extra 4-5GW of closures on top would likely be enough for the remaining coal and gas plant to return to sustainable margins by 2014/15.

In short, whether the margins for Germany's coal and gas-fired generators return to acceptable and sustainable levels from 2014-15 will now depend above all on the strategic decisions they make on capacity closures and new build.

German power prices: where are we now?

Germany's baseload and peakload power prices reached all-time highs in the summer of 2008, but by the fourth quarter of 2008, German GDP and electricity demand were contracting, heralding a 5% contraction in both over the course of 2009. Despite a return to growth in 2010, total demand for electricity this year will still be below the level of 2008.

At the same time, the German Government has recently decided to propose a prolongation of the operating lives of Germany's nuclear-power plants, a decision that might ultimately mean all of the country's nuclear plants are still running in 2020. As a result of these changes, the outlook for capacity margins in the foreseeable future looks much healthier than it did in the early summer of 2008.

With capacity margins now much more comfortable, and the outlook for demand still muted, the forward curves for baseload and peakload power out to 2014 are currently very subdued, and with coal and oil prices in particular still at very robust levels, the margins for coal and gas-fired generators are at three-year lows.

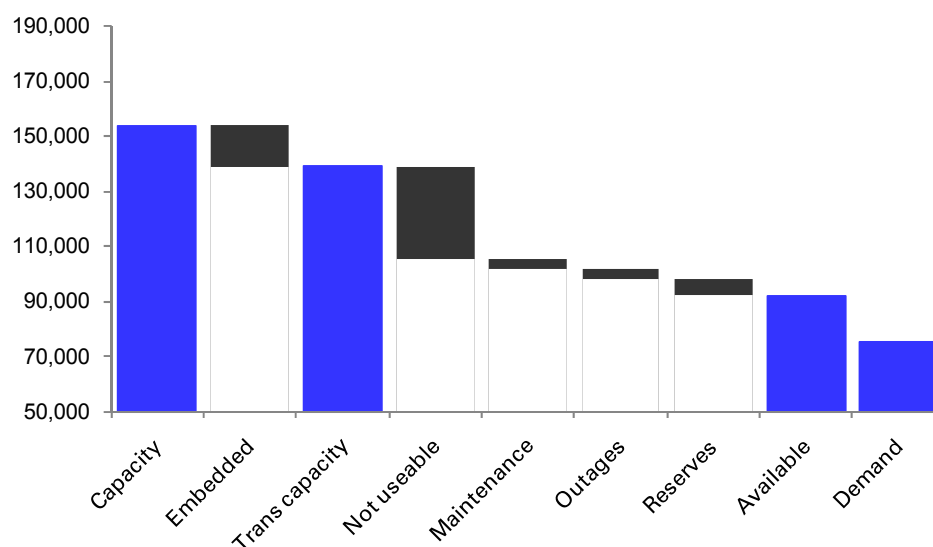
However, until 2012 fossil-fuel generators' margins are in reality higher than the spreads implied by the forward curves would indicate because over Phase 2 of the ETS we estimate that they are on average only paying 35-40% of the cost of CO₂. By contrast, they are able to pass on the full market value of EUAs in their selling price over this period.

With the move to full EUA auctioning from 2013, though, this extra cash benefit above and beyond the clean spread will disappear. As a result, we think the move to full EUA auctioning from 2013 will throw into stark relief the question of whether it is worth continuing to keep many of the older coal and gas-fired plants open, as the free CO₂ allowances they receive until 2012 are currently covering a significant proportion of their fixed operating costs.

The outlook for capacity margins over 2011-14

Figure 1 shows our estimate of capacity and peak load for 2009/10.

Figure 1: DB estimated de-rated capacity margin for 2009/10 (MW)



Source: Deutsche Bank after BDEW

To assess how well demand is covered by generation capacity we look at the de-rated capacity margin. We present this on a similar basis as historic published data by the transmission-network operators. This compares peak-demand experiences on the transmission system to capacity available to meet this load.

To arrive at these figures we adjust installed capacity and demand downwards to take into account 'embedded generation', i.e. demand that is met through on-site generation or generation connected to the distribution network.

At the end of 2009 total capacity stood at 153.8GW. After stripping out embedded generation, we estimate that this leaves around 139GW of capacity to cover the transmission peak demand for the winter of 2009/10. This must be adjusted downward further to remove unusable capacity (including much of the renewable capacity such as solar and wind, which may not be available at peak), capacity offline for outages and maintenance, and capacity needed to cover system-service reserves. For 2009/10 we estimate that around 92GW of reliably available capacity was available to cover peak demand of about 75GW. This would imply a de-rated capacity margin of about 22%.

The question is, what will this look like by 2014?

To answer this question we here consider (i) the outlook for demand over our forecast period, (ii) the revised legislation on nuclear power plants, (iii) the prospects for fossil-fuel plant closures and new entrants, and (iv) the extent to which the Government's indicative trajectory for additional renewable capacity out to 2014 is likely to be achieved.

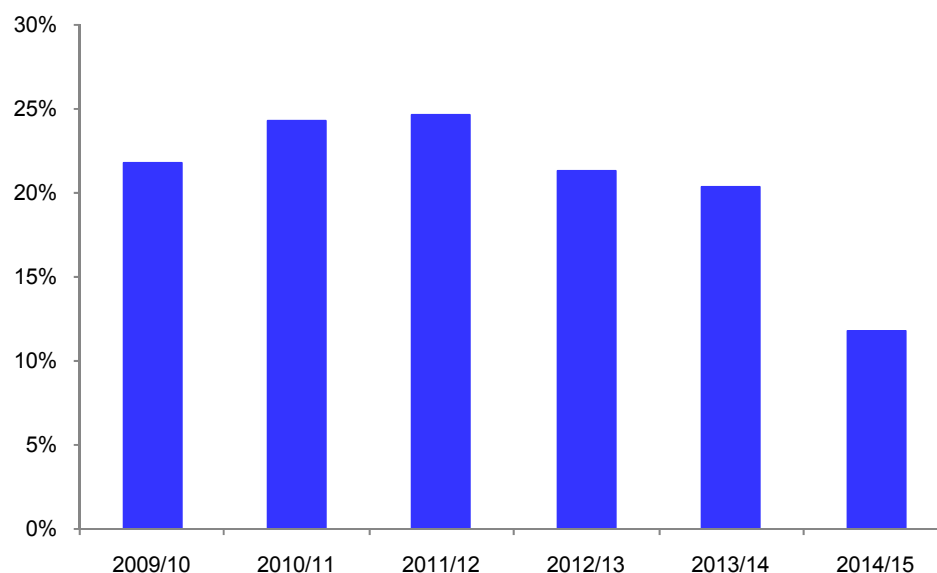
As far as demand is concerned, we expect a rebound of 3.5% in 2010 to 532TWh, followed by a more modest trend growth rate of 0.75% per year thereafter, while following the recently passed revised legislation on the operating lives of Germany's nuclear plants, our base-case scenario assumes that all of them will now ultimately operate for an extra 12 years on average.

In terms of the prospects for net changes to fossil-fuel capacity over the next four years, we expect significant activity with regard to both closures and new entrants. Based on generic operating lifetimes of 45 years for coal and lignite stations, 30 years for CCGTs and 40 years for other fossil-fuel plant, we see potential for 17.6GW of closures by the end of 2014, against which we expect 12.1GW of new capacity to come on-stream over the period.

Although there is a lot more planned new fossil-fuel plant at the pre-approval stages, we do not think it is reasonable to assume that any of that will be up and running before 2015, as 10.6GW has already been postponed or cancelled owing to the fact that forward prices and margins are well below new-entrant levels. Overall, this means that we are actually expecting a net decline in fossil-fuel capacity by 2014 of 5.5GW.

With regard to the new renewable capacity that could be on the system by 2014, we expect a very significant increase of 27GW over the period, 21 GW of which will in our view be solar capacity, and the rest a broadly even mix between onshore wind, offshore wind, and bio-mass. The outlook here is much more positive than for fossil-fuel fired capacity because the investment decision for renewable projects is independent of wholesale prices, depending instead primarily on the level at which the feed-in-tariffs are set.

Putting all of this analysis together, our base-case scenario projects a net increase in total installed capacity by 2014 of 22GW.

Figure 2: Estimated progression of German de-rated capacity margin

Source: Deutsche Bank

However, as all of this net increase is attributable to renewable capacity with much lower availability levels than fossil-fuel plants, the de-rated capacity margin actually declines over our forecast period, to 12% by the winter of 2014/15 against our estimated starting point of 22% in 2009/10 (Figure 2).

The outlook for prices and spreads over 2011-14

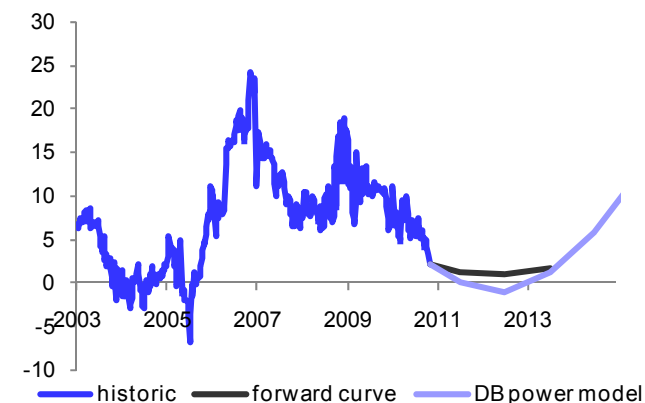
Having made our assumptions on the outlook for demand and changes to the capacity mix over 2011-14, we conclude by setting out the forecasts for prices and spreads generated by our model on the basis of two scenarios for commodity prices.

First, we plug in our own assumptions on demand and changes in the capacity mix as set out in Section 2 of this report, and take the current forward curves for gas, coal, and oil as our commodity-price inputs. In this way we are able to impute what the forward baseload power curve is pricing in with regard to demand and capacity changes.

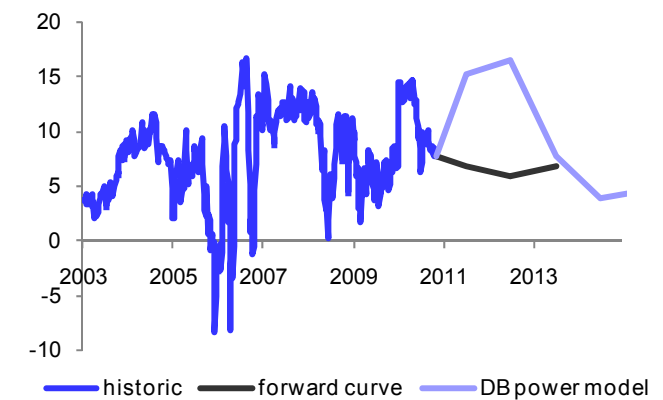
Using these inputs, our model generates forward power prices and clean dark and spark spreads that are very close to the market values currently shown by forward power prices and spreads. This would suggest that the market is pricing in very similar assumptions to our own as far as the overall outcome on demand and capacity changes out to 2014 are concerned.

Second, we again take our own assumptions on capacity and demand but this time we use our own DB assumptions for the forward prices of gas, coal, and oil. We have lower gas prices over 2011-13 than those shown in current forward curves, but with gas prices recovering more rapidly thereafter than the market is assuming.

By contrast we have higher coal and carbon prices relative to forward curves over 2011-12, but with coal prices falling back against the forward curve over 2013-14 as we assume that more global coal capacity (mining and exporting) comes onstream by those dates.

Figure 3: DB base-case clean dark spreads (€/MWh)

Source: Deutsche Bank

Figure 4: DB base-case clean spark spreads (€/MWh)

Source: Deutsche Bank

Using our own commodity-price inputs, we generate a slightly more positive projection for baseload prices over 2011-12 than that shown in the current forward baseload curve, with more positive clean spark spreads but more negative clean dark spreads than the market is currently projecting. After 2013, our baseload-price projections are essentially in line with those of the current forward curve.

The conclusion under our base-case scenario is that once fixed operating costs are taken into account beyond 2012 (i.e. after the move to full EUA auctioning), the outlook for the majority of Germany's coal and gas-fired generators is bleak.

Coal generators will be running at an all-in loss over the entire 2011-14 period, and while gas generators do better than coal over 2011-12 given our low forecasts for market gas prices clean spark spreads drop sharply over 2013-14, with older gas plant then making all-in losses in excess of -€10/MWh generated, and even new CCGT plant failing to earn its cost of capital.

However, while the German market undoubtedly looks to have material surplus capacity over 2011-13, an extra 4-5GW of closures above and beyond what we are pricing in under our base-case scenario would bring the de-rated capacity margin down below 10% by the winter of 2014-15, and to below 15% already by the winter of 2013-14. With these kinds of margins, prices and spreads would be materially healthier by 2014/15 than our base case assumes.

Accordingly, whether the margins for Germany's coal and gas-fired generators return to sustainable levels from 2014-15 depends above all now on the decisions these generators themselves make over the next four years on capacity closures and new build.

Overall, the conclusion from our modeling is that while the 17.6GW of fossil-fuel closures we have assumed in our base-case scenario – or 5.5GW of net fossil-fuel closures after adjusting for assumed new build -- will not be enough to enable much of Germany's coal and gas-fired capacity to cover its fixed costs over 2013-14, an extra 4-5GW of closures on top would likely be enough for the remaining coal and gas plant to return to sustainable margins by the end of our forecast period.

This reflects our analysis of capacity margins, whereby even under our base-case assumption of 17.6GW of fossil-fuel closures we already expect a level of tightness by the winter of 2014/15 similar to that seen in 2006/07. With our base-case scenario projecting a de-rated capacity margin by the winter of 2014/15 of only 12%, the German generation system will still be able to cover its expected peak load at that time, but net exports at peak will leave little surplus.

Assumptions and caveats

The key variables that drive power prices are demand, capacity margins, and the prices of the commodities used by the fossil-fuel generators that set the price most of the time (coal, gas, and CO₂).

We set out our detailed assumptions on electricity demand and the changes we expect in the capacity mix over 2011-14 in Section 2, and then take these assumptions into our pricing analysis in Section 3, where we also set out our assumptions on commodity prices.

Our pricing analysis considers two scenarios for commodity prices, the first taking the current forward curves, and the second DB's own forecasts for commodity prices over 2011-14. This second scenario using DB assumptions on all variables gives us our base case for power prices over 2011-14.

As far as the key caveats to our analysis are concerned, we would highlight three in particular:

Caveat 1: Demand from neighboring markets

Our analysis in this report concentrates on the internal dynamics of the German market. In reality, Germany is already a very significant hub for the broader central European market with a net transfer capacity of c.16GW and inter-connections with nine neighboring countries. To the extent that some of these markets are likely to exhibit higher growth or tighter capacity margins than Germany itself over the next few years, we think it is reasonable to assume that there will be an increasing demand for net exports from Germany over time (notably from the Czech Republic, Austria, Switzerland, and France).

Depending on the strength of this potential growth in demand for German exports, the need for capacity closures of older fossil-fuel plant in Germany to bring margins back to healthier levels by 2014/15 could be lower than the 21-23GW we think will be necessary.

Caveat 2: The profitability of gas plants as shown by clean spark spreads

In our analysis of the profitability of gas-fired generators throughout this report, we look at spark spreads using either the market price for gas or our own projections for the market price of gas.

In reality, most gas-fired generators in Germany, whether older OCGT or brand new CCGT plant, will source most (if not all) of their gas under long-term contracts indexed to oil prices. At the moment EU market prices are well below oil-indexed prices, and we believe this pattern will hold until 2014, after which we expect to see market prices move back towards convergence with oil-indexed prices. This means that our analysis of clean spark spreads is in all likelihood over-stating the profitability of gas-fired generators over 2011-14.

Against this, however, there are two mitigating factors to mention.

First, as far as our stylized analysis of the profitability of OCGT generators in Section 1 below is concerned, we take the standardized peakload price as the average price earned when in reality OCGT plant will for some or even much of the time be receiving "super-peak" prices, i.e. prices above the standardized peakload level.

Second, a significant amount of OCGT capacity in Germany is co-generation plant, i.e. plant that generates heat as well as power. Revenue from the heat sales will help to cover fixed costs but is not captured in our stylized analysis of clean spark spreads for OCGT plant.

On balance, we think that for the purposes of our analysis in this report these mitigating factors more or less offset the flattering impact on clean spark spreads from using market rather than oil-indexed prices, and are therefore comfortable with the overall conclusions we reach on the outlook for gas stations' profitability over 2011-14.

Caveat 3: Fossil-fuel plant closures and the allowed transfer of free EUA allocations

Our projections for fossil-fuel plant closures in Section 2 below assumes that the owners of such plant are portfolio generators rather than IPPs and that they will therefore be able to transfer the free allocations of EUAs received by any facilities that they close over Phase 2 of the ETS to other installations that they own. We make this assumption because it is our understanding that Germany's Phase-2 NAP allows ETS operators to transfer free EUA allocations between their own installations within a period of three months after any closure.

The structure of this report

This report is divided into three main sections, with a glossary at the end to explain the acronyms used throughout.

Section 1 looks at how wholesale prices and generators' margins have evolved since 2008 before highlighting the hard choice now looming for incumbent hard-coal and gas-fired generators: as they face up to clean spreads at three-year-lows and the prospect of full EUA auctioning from 2013, we think that many older, less efficient coal and gas plants will not be able to cover their fixed operating costs beyond 2012.

Section 2 sets out our base-case analysis of the evolution in capacity margins over 2010-14, considering (i) the outlook for demand over our forecast period, (ii) the revised legislation on nuclear power plants, (iii) the prospects for fossil-fuel plant closures and new entrants, and (iv) the extent to which the Government's indicative trajectory for additional renewable capacity out to 2014 is likely to be achieved.

Section 3 then concludes our report with a detailed look at the implications for power prices and spreads given our assumptions on demand and capacity changes out to 2014, and using both forward commodity prices and our own projections for commodity prices.

Valuation and risks

Our power-price analysis is based on a bottom-up, plant-by-plant model of the German power system. For each quarter of the year we construct a load-duration curve, estimate the output of non-thermal generation, and then model the price-setting thermal generation.

We model over 280 generating units on the system and estimate marginal costs for fossil stations based on assumed delivered fossil-fuel prices and thermal efficiencies for the generating units. Our modeling of the price-setting plant produces a price-duration curve for each quarter, showing the expected level of prices at different times of the quarter, ranked from the hour of highest price to the hour of lowest price.

This price-duration curve includes adjustments we make for system constraints: at peak times (when prices rise above short-run marginal costs as the system is tight and additional capacity is needed to ramp up to meet demand); and at the periods of lowest demand (when plant may have to be paid to temporarily reduce generation, particularly if renewable output is high at times of low demand).

There are both downside and upside risks to our modeling of German power prices.

On the downside, we would highlight the continuing fragility of the EU macro-economic recovery, and in particular the ongoing fiscal crises in a number of Eurozone Member States. This poses a broader risk to the economic health of the EU economy as a whole, and hence to the rate of future growth in German GDP and electricity demand. Other risks to the downside would be the possibility of a higher amount of new fossil-fuel build and/or fewer closures of older fossil-fuel plant over 2011-14 than we have assumed in our base-case scenario. Lower coal and/or gas prices than we are assuming would also lead to lower average power prices than those generated under our base-case scenario.

On the upside, the main risks would be the possibility that some or all of Germany's nuclear-power stations might not ultimately receive lifetime extensions as we have assumed, and that there will be less new fossil-fuel build and/or more closures of older fossil-fuel plant than we are forecasting. Higher coal and/or gas prices than we are assuming would also lead to higher average power prices than those generated under our base-case scenario. Higher demand from neighbouring markets than we have assumed would also be an upside risk to our base case.

For more details on our valuation and risks please see pages 53-56 below.

1. German power prices: the essential background

In this section we begin with a brief review of how wholesale prices and generators' margins have evolved since 2008 before highlighting the hard choice now looming for incumbent hard-coal and gas-fired generators: as they face up to clean spreads at three-year-lows and the prospect of full EUA auctioning from 2013, we think that many older, less efficient coal and gas plants will not be able to cover their fixed operating costs beyond 2012.

The main drivers of power prices and margins in the last three years have been commodity prices and the contraction in demand caused by the global and EU recessions.

After reaching an all-time high of \$147/bbl in July 2008, oil prices crashed to \$35/bbl in February 2009 before recovering over the second half of 2009 and so far in 2010 averaging their second-highest level ever in nominal US\$ terms (only in 2008 have prices sustained a higher average nominal level). Coal, gas, and CO₂ prices have all experienced similar gyrations over this period, and this has had a very big impact on baseload and peakload prices and hence on fossil-fuel generators' margins.

Meanwhile, the impact of falling commodity prices as the global recession began in late 2008 was compounded by that of falling domestic demand. By the fourth quarter of 2008, however, German GDP and electricity demand were contracting, heralding a 5% reduction in both over the course of 2009. Despite a return to growth in 2010, total demand for electricity this year will still be below the level of 2008.

At the same time, the German Government has recently decided to propose a prolongation of the operating lives of Germany's nuclear power plants, a decision that might ultimately mean all of the country's nuclear plants are still running in 2020 (we set out our assumptions on this point in Section 2 below). As a result of these changes, the outlook for capacity margins in the foreseeable future looks much healthier than it did in the summer of 2008.

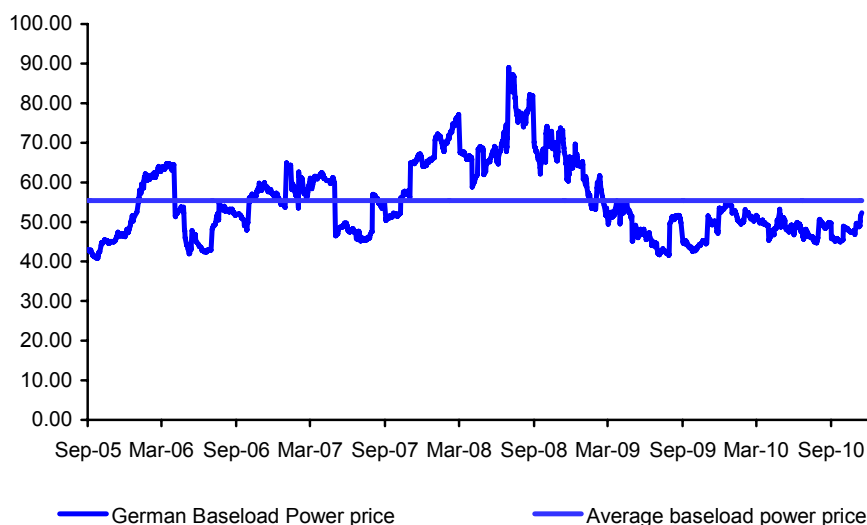
With capacity margins now much more comfortable, and the outlook for demand still muted, the forward curves for baseload and peakload power out to 2014 are currently very subdued, and with coal and oil prices in particular still at very robust levels, the margins for coal and gas-fired generators are at three-year lows.

However, until 2012 fossil-fuel generators' margins are in reality higher than the spreads implied by the forward curves would indicate because over Phase 2 of the ETS we estimate that they are on average only paying 35-40% of the cost of CO₂. By contrast, they are able to pass on the full market value of EUAs in their selling price over this period.

With the move to full EUA auctioning from 2013, though, this extra cash benefit above and beyond the clean spread will disappear. As a result, we think the move to full EUA auctioning from 2013 will throw into stark relief the question of whether it is worth continuing to keep many of the older coal and gas-fired plants open, as the free CO₂ allowances they receive until 2012 are currently covering a significant proportion of their fixed operating costs.

Wholesale prices have fallen sharply from their 2008 highs ...

Figure 5 shows the evolution of the one-year forward German baseload-power price over the last five years.

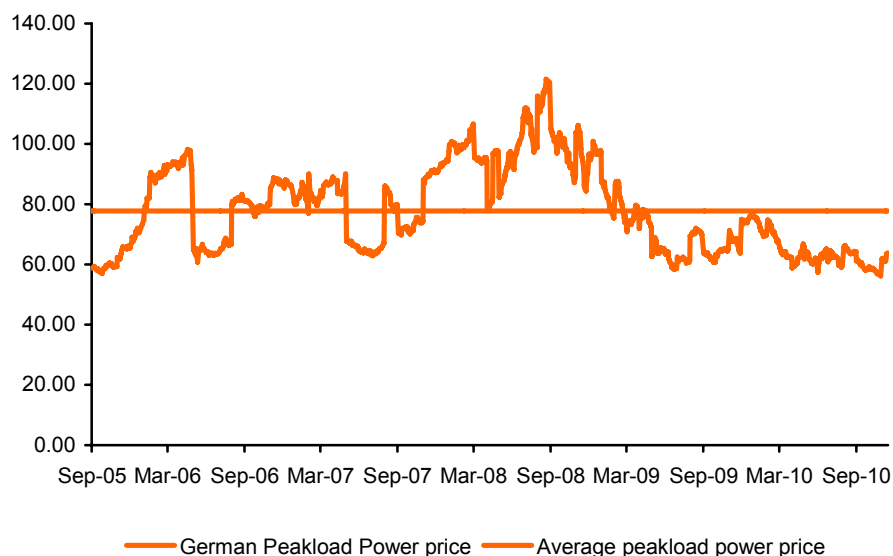
Figure 5: German one-year forward baseload prices, 2005-10 (€/MWh)

Source: Deutsche Bank

As can be seen, the baseload price reached an all-time high of nearly €90/MWh in July 2008 as oil rose to a record high and gas, coal, and carbon prices all followed in its wake, with the carbon price at this time also reflecting the perception that the Phase-2 EU-ETS cap was going to be tight.

During the first half of 2008 the EU and German economies were still growing steadily, and the "Grand Coalition" government between the CDU/CSU and SPD parties was not in a position to revoke the legislation passed in 2002 decreeing that all of Germany's nuclear power plants should be phased out by 2022.

As a result, there was concern over future capacity margins and hence a potential need for a significant new-build programme at a time when commodity prices were at all-time highs.

Figure 6: German one-year forward peakload prices, 2005-10 (€/MWh)

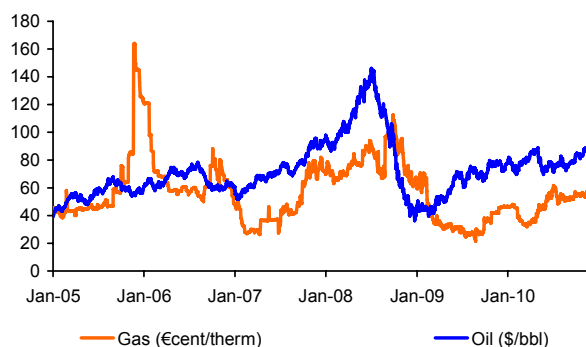
Source: Deutsche Bank

The evolution in one-year forward peakload prices shown in Figure 6 displays the same pattern for the same reasons.

As can be seen in Figures 5 and 6, however, from the highs of July 2008 German power prices more than halved over the following 12 months, reflecting the onset of the global financial crisis and the ensuing global and EU recessions.

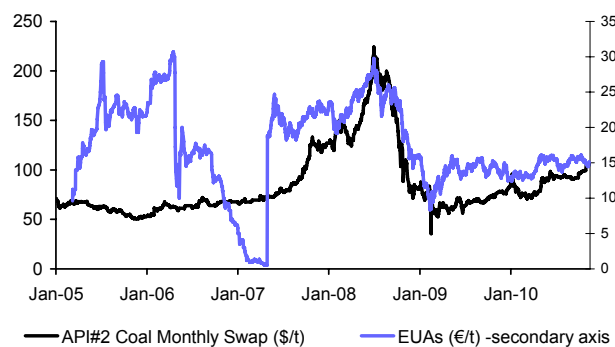
The impact of the global economic slowdown from the summer of 2008 was felt first in the form of a very sharp fall in commodity prices, led by oil. Figure 7 shows the trend in prompt oil and gas prices over the last five years, and Figure 8 the trend in prompt coal and EUA prices.

Figure 7: EU prompt oil and gas prices, 2005-10



Source: Deutsche Bank

Figure 8: EU prompt coal and CO2 prices, 2005-10



Source: Deutsche Bank

Oil prices peaked in July 2008 at \$147/bbl, but then fell by 77% over the next eight months before bottoming out at \$35/bbl in February 2009. The collapse in oil prices was matched by the declines in gas, coal, and CO2 prices, all of which registered very similar percentage declines over this period, and all of which also reached a trough in February 2009.

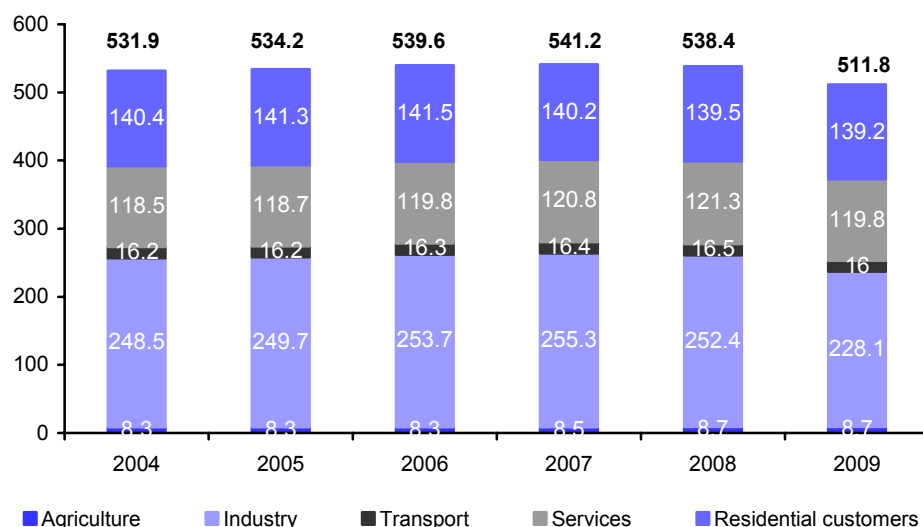
The falling prices of these commodities fed directly into lower production costs for Germany's fossil-fuel generators, but their impact on power prices was compounded by the contraction in German GDP that took hold from the fourth quarter of 2008.

According to the German Federal Statistics Office, German GDP contracted by 1.9% in the fourth quarter of 2008 on a year-on-year basis, and for 2009 as a whole the economy contracted by 4.7%. Overall, GDP contracted for five consecutive quarters before starting to grow again in Q1 of 2010.

Similarly, German electricity demand fell by 5% in 2009 after starting to fall in Q4 of 2008, this being the first time that German power demand had declined since 1993 (the fall at that time being due to the collapse of large parts of eastern Germany's industrial base in the wake of reunification).

As shown in Figure 9, demand peaked in 2007 at 541TWh, falling back slightly already in 2008 but then declining by 5% in 2009 as the economy contracted by the same amount.

Overall, then, while one-year forward baseload prices have averaged €55/MWh over the last five years, and peakload prices €78/MWh, they have actually been exceptionally volatile, reflecting the dynamic interplay of their key drivers over this period.

Figure 9: German electricity demand, 2004-09 (TWh)

Source: RWE from BDEW

And with power and commodity prices experiencing so much volatility, the margins of fossil-fuel generators have also been subject to significant gyrations.

...and so have fossil-fuel generators' margins

The gross margins of fossil-fuel generators are a function of the spread they make between the cost of their fuel inputs and the selling price of the electricity they produce.

For a coal-fired generator this gross margin is commonly referred to as the "dark spread", and for a gas-fired generator the "spark spread", while for lignite generators we might refer to this margin as the "brown spread" (lignite is also known as brown coal).

Since the introduction of the EU-ETS in 2005, fossil-fuel generators have also had to reflect the price of CO₂ in their cost base, such that the clean spread denotes the gross margin after accounting for the cost of carbon (so, the clean dark spread, for example, denotes the margin earned by a coal-fired generator net of coal and CO₂-input costs).

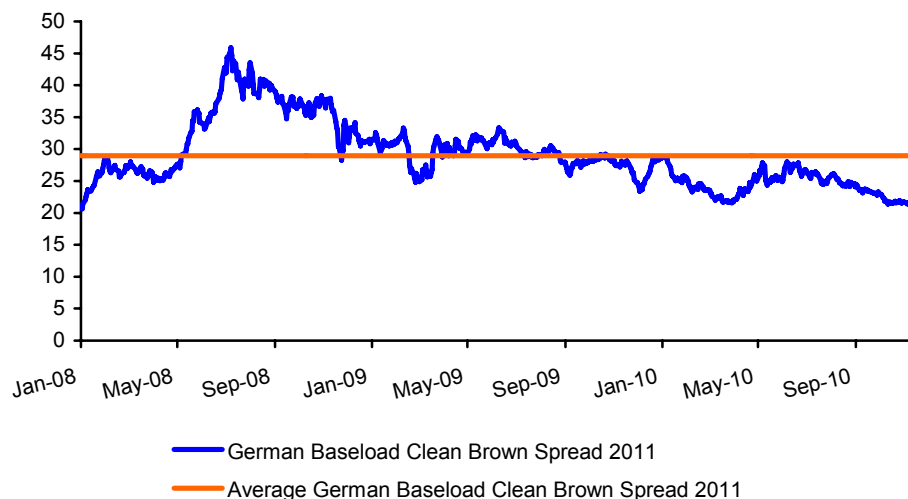
Figures 10-12 show the trend in clean spreads for the different fossil-fuel fired generators since January 2008 on the forward sale of electricity for 2011 (i.e. on the Cal-11 contract).

The evolution in clean lignite spreads, 2008-10

Figure 10 shows our estimate of the clean spread for lignite generators. We have calculated this spread over time by taking the price of the baseload Cal-11 contract and deducting from this our estimate of (i) the fuel cost to a lignite generator (we here assume a constant €7/MWh), and (ii) the CO₂ cost to a lignite generator with an efficiency rate of 33% (such a plant would emit 1.15 tonnes of CO₂ per MWh generated).

On this basis it can be seen that lignite generators have achieved an average clean spread over the last three years of nearly €30/MWh, with a peak of €45/MWh being reached in July 2008. The reason the spread for lignite generators peaked in 2008 despite record high CO₂ prices is the very low cost of brown coal relative to the record high fuel-input prices for hard-coal and gas-fired generators at that time (lignite is not an internationally traded commodity, and its price did not increase over the course of 2008 with those of other commodities).

Figure 10: German clean lignite spread for baseload Cal-11 contract, Jan 2008-November 2010 (€/MWh)



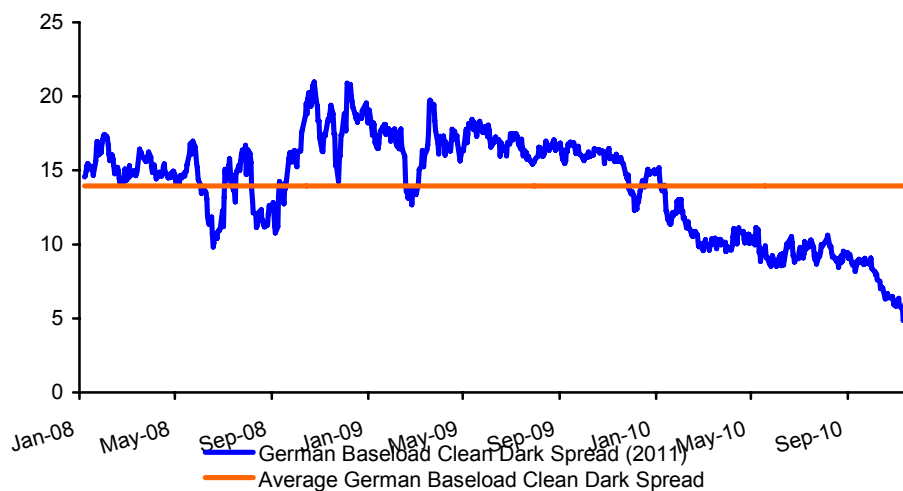
Source: Deutsche Bank

As coal and gas prices fell over the second half of 2008 and power prices came off accordingly, the clean spread for lignite also declined, but it still remained around €30/MWh for most of 2009 even as the German economy and electricity demand contracted by 5%. The spread has been more volatile in 2010 but has been lower throughout most of the year compared with 2009, averaging about €25/MWh and currently at €23/MWh, a level last seen in early 2008.

The evolution in clean dark spreads, 2008-10

Figure 11 then shows the trend in the gross margin for a baseload coal-fired generator over the same period.

Figure 11: German clean dark spread for baseload Cal-11 contract, Jan 2008-November 2010 (€/MWh)



Source: Deutsche Bank

Hard-coal generators have achieved an average clean spread over the last three years of just under €15/MWh (almost exactly half that of lignite generators), with a peak of €20/MWh being reached in October and December 2008. This is explained by the fact that as the global financial crisis took hold over the second half of 2008 coal and carbon prices reacted more quickly on the downside than did demand, with the result that the input prices for hard-coal generators fell more sharply than the power price.

So, although baseload prices peaked on 1 July 2008 at €89/MWh, the clean dark spread on that date was only €11/MWh. Then, as coal and carbon prices fell more sharply than baseload prices over the following six months, the clean dark spread widened to €20/MWh by 28 December even though power prices had fallen to €55/MWh by this time.

However, the clean dark spread then contracted over 2009 as the impact of lower commodity prices on power prices was compounded by reduced demand, and despite modest demand growth this year the spread has fallen further over 2010, particularly in the last three months. In our view this most recent further deterioration in the spread reflects stable coal and CO₂ prices at relatively robust levels but slightly weaker power prices, possibly in part owing to the Government's decision in early September to propose an average 12-year lifetime extension for Germany's nuclear fleet.

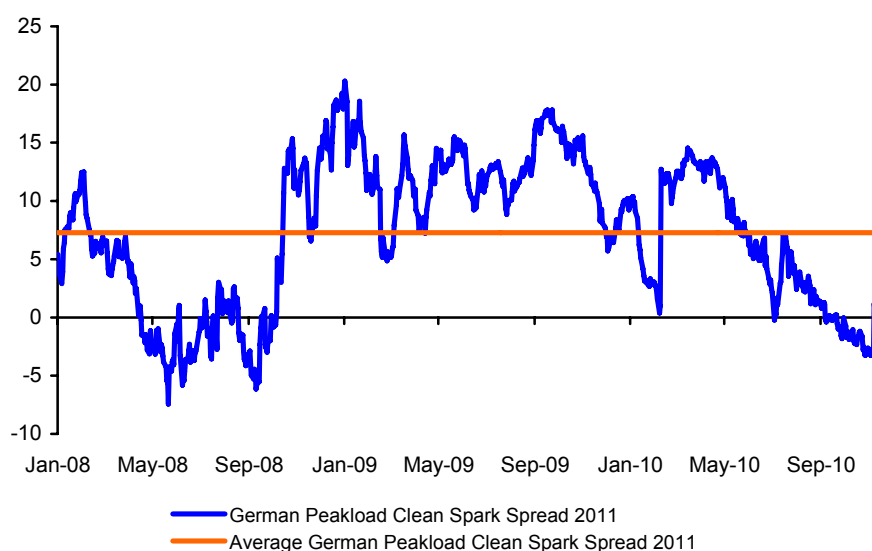
At the moment the spread of €5/MWh represents the lowest level seen in the last three years.

The evolution in clean spark spreads, 2008-10

Figure 12 then shows the trend in the gross margin for a peakload gas-fired generator over the same period. We here assume an efficiency rate of 37% and hence average CO₂ emissions of 0.53 tonnes/MWh generated.

On these assumptions gas-fired generators have achieved an average clean spread over the last three years of €7/MWh, with a peak of €20/MWh in early January 2009.

Figure 12: German clean spark spread for peakload Cal-11 contract, Jan 2008-November 2010 (€/MWh)



Source: Deutsche Bank

Again, this reflects the fact that gas and carbon prices reacted more quickly on the downside to the global financial crisis than did demand, with the result that the input prices for gas-fired generators fell more sharply than the power price.

So, although Cal-11 peakload prices reached their highest level on 7 July 2008 at €128/MWh, the clean spark spread on this date was only €6/MWh, whereas by 2 January 2009 it had widened to €20/MWh even though peak power prices had by then fallen to €87/MWh.

In contrast to clean dark spreads, clean spark spreads were then quite resilient over the course of 2009 owing to very weak gas prices (particularly in Q3), but since mid-September 2010 the spread is now negative again. On our calculations it is now trading at -€3/MWh, a level last seen in the summer of 2008 when oil prices were at record-high levels.

As with the clean dark spread, this most recent further deterioration in the gross margin for gas-fired generators reflects stable gas and CO₂ prices, but weaker peakload power prices (down by €12/MWh over the last six months).

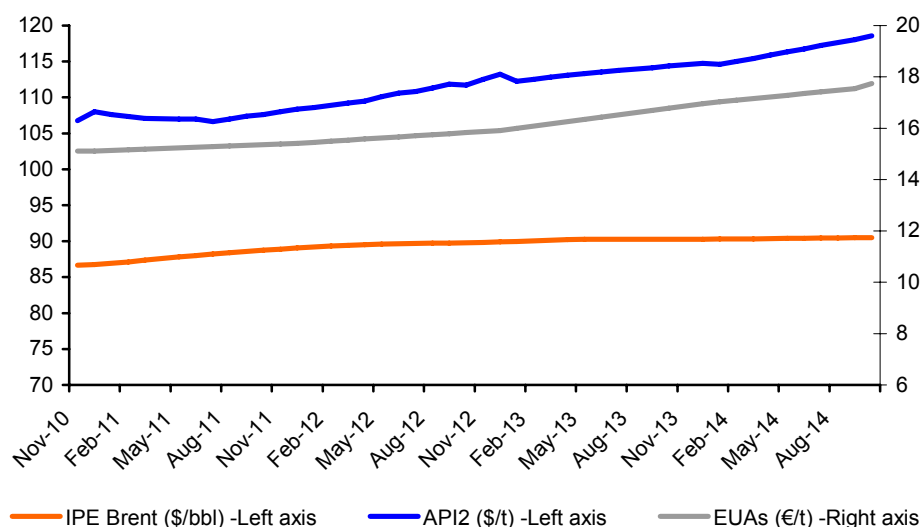
Currently, then, clean spreads for lignite, coal, and gas-fired generators in Germany are at or near the lowest levels seen in the last three years. However, while the clean spread for lignite remains very healthy at over €20/MWh, for coal plants gross margins are much lower at €5/MWh and a gas-fired generator with the profile we have outlined above is actually facing a negative spread at the moment of -€3/MWh.

The question is, where do we go from here?

What are the forward curves saying out to 2014?

As just discussed, clean dark and clean spark spreads are currently at three-year lows and at these levels coal generators are selling forward some €5/MWh above cash costs, and gas generators on our generic assumptions at cash costs. Indeed, the real situation for most gas generators is likely even worse than indicated in Figure 12, as most German gas plants will source most of their fuel on long-term contracts indexed to oil, and oil-indexed prices are well above market prices at the moment (see Caveat 2 in our *Executive Summary* above).

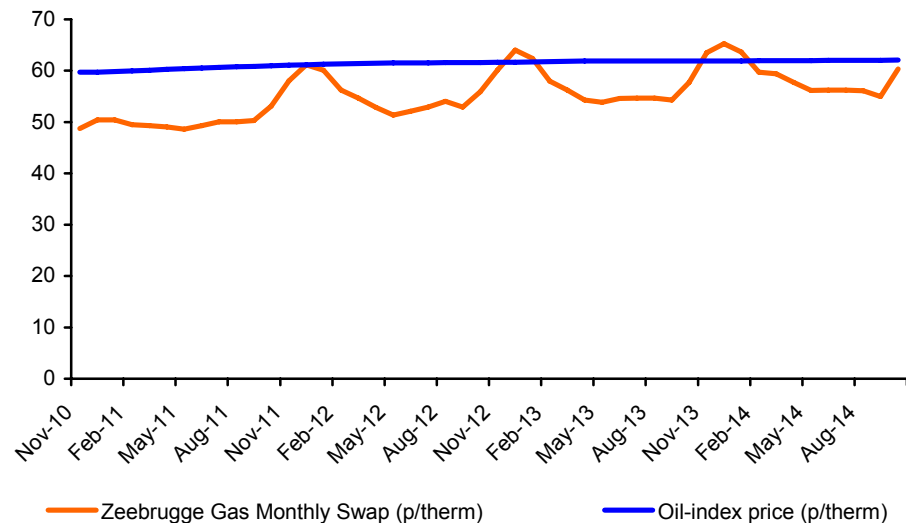
Figure 13: Forward curves for oil, coal, and CO₂, 2011-14



Source: Deutsche Bank

Figure 13 shows the current forward curve for oil, coal, and CO₂ out to 2014, while Figure 14 shows forward gas prices at the Zeebrugge hub and as implied under oil-indexed contracts.

Figure 14: Forward curve for EU gas at the Zeebrugge hub and implied forward curve for oil-indexed contracts, 2011-14



Source: Deutsche Bank

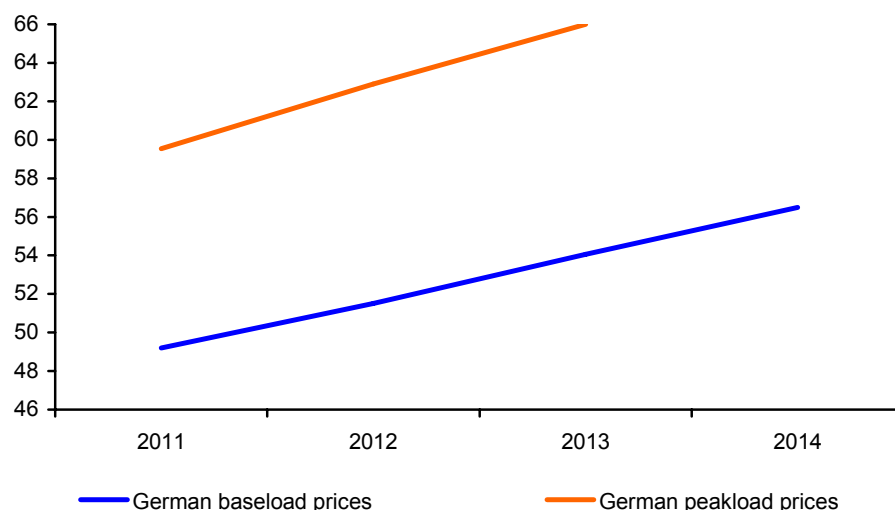
As shown in Figure 13, oil, coal, and EUA curves are all in contango, but their steepness varies. Oil prices are currently trading at \$87/bbl, and with a curve in mild contango are showing \$91/bbl out to October 2014. The coal curve is in a steeper contango pattern, with prices rising from \$107/tonne today to \$118/tonne by October 2014. For EUAs, the curve is showing a steep rise from €15/tonne today to €18 by the end of 2014.

In terms of absolute prices, oil and coal are back at levels last seen in the autumn of 2008 when the global recession was just beginning in earnest, while the trajectory for CO₂ reflects market's anticipation of the impact of a tighter ETS cap from 2013. The strength of oil and coal reflects continuing strong demand from China in particular, and such strong energy prices at a time of only modest recovery in the EU is likely to be a drag on the pace of the ongoing EU rebound, and hence on the strength of recovery in demand for electricity.

Figure 14 shows the difference between EU market gas prices and oil-indexed prices, and further underlines the disconnect between continuing strong global demand for oil, but weak EU demand for gas: oil-indexed gas prices are on average 13% higher than market prices over the next four years. Given that German gas-fired generators rely very heavily on oil-indexed contracts, most of their fuel costs will be at prices materially above current market levels, exacerbating further the already depressed outlook for clean spark spreads shown in Figure 12 above.

Figure 15 then show the current forward curves for baseload and peakload power out to 2014. With power prices barely enough to cover the cash costs of coal and gas-fired plant, the current forward curve remains well below new-entrant cost levels: the current 2011 baseload price is €49/MWh, whereas we estimate new baseload gas price would need a price of €65-70/MWh, and new baseload coal a price of €70-75/MWh.

(It therefore seems reasonable to us to conclude that no new fossil-fuel plant will be built in the foreseeable future above and beyond the 12-13GW already under construction, a point we examine in greater detail in Section 2 below).

Figure 15: German baseload and peakload power forward curves (£/MWh)

Source: Deutsche Bank

In short, given the outlook for both commodity and power prices, the near- to medium-term future for incumbent coal and gas-fired generators looks very bleak. Under these circumstances it seems legitimate to ask how long this situation can go on before generators start seriously contemplating an accelerated mothballing or closure programme for their older, least efficient coal and gas plants.

In this respect, it must be remembered that for power sold until the end of 2012 (i.e. the end of Phase 2 of the ETS), fossil-fuel generators' margins are in reality higher than the spreads shown in Figures 10-12 above would indicate. This is because they are not yet paying the full price of CO₂. Indeed, in aggregate we estimate that they are on average only paying 35-40% of the cost of CO₂ over 2008-12 whilst receiving the full market value in their selling price.

With the move to full EUA auctioning from 2013, however, this extra cash benefit above and beyond the clean spread will disappear. As a result, we think the move to full EUA auctioning from 2013 will throw into stark relief the question of whether it is worth continuing to keep many of the older coal and gas-fired plants open, as the free CO₂ allowances they receive until 2012 are currently covering a significant proportion of their fixed operating costs.

Accordingly, it is to a closer examination of the impact of full auctioning that we now turn.

The impact of full EUA auctioning on incumbents

Figure 16 shows the breakdown of free EUA allocations versus emissions in 2009 for (i) all combustion installations in Germany covered by the ETS, and (ii) more specifically for electricity-generating installations (i.e. the larger power plants). At the same time, we also have data from RWE for its own free allocations versus emissions in 2008.

Figure 16: Free EUA allocations versus CO₂ emissions in Germany, 2009 and 2008

	Free EUAs granted (m)	CO ₂ emissions (Mt)	Free allocations as a percentage of total emissions
All combustion installations (2009)	259.9	338.6	76.7%
All electricity installations (2009)	215.6	300.2	71.8%
RWE electricity installations (2008)	85.0	141.0	60.3%

Source: RWE, Deutsche Bank

From these numbers it can be seen that the free allocation of EUAs covered 77% of emissions from all combustion installations in 2009. These numbers include the allocations not only to the larger power generators, but to all combustion installations in excess of 20MW, including those in public-sector buildings (such as hospitals and schools/universities), and a limited part of the embedded generation on industrial sites (note, however, that most of the embedded industrial generation is categorized in the ETS registry under the relevant sectors themselves). What this means is that combustion installations only had to purchase 23% of their EUAs in 2009 in order to meet their compliance obligations.

The numbers for the electricity sector more specifically as given by RWE for 2009 show that the larger power generators were allocated 216m EUAs for free versus emissions of 300Mt, meaning that generators overall would have had to purchase 28% of their EUAs in 2009. In 2008, meanwhile, RWE itself received 105m EUAs versus emissions of 149Mt, and so had to purchase 40% of its allowances on the market.

From all of this we infer that (i) the larger power plants have received a slightly smaller free allocation of EUAs over Phase 2 than combustion installations as a whole, and (ii) that the big four power generators (here taking RWE as a proxy for these companies as a whole) a smaller free allocation than all electricity installations combined.

Even so, from these numbers and from our forecast for the evolution in emissions over 2010-12, we think it is fair to assume that the big power generators in Germany that between them own most of the large fossil-fuel power stations will end up receiving free allocations amounting to 60-65% of their emissions over Phase 2.

The question, then, is how the transition to full auctioning of EUAs from 2013 will impact the profitability of lignite, coal, and gas-fired plants.

For the purposes of this analysis, we have looked first at the total output of lignite, coal, and gas generators in 2009 as given by RWE in its 2010 factbook. We then assume a generic efficiency rate for each plant type, thereby deriving CO₂ emissions for each type in 2009. For the output from gas plants, we have assumed that of the total 77TWh generated in 2009, 60TWh came from OCGT plants, and the remainder from CCGT stations, and for the purposes of our analysis here we confine ourselves to the OCGT plant.

Figure 17 below shows these key elements for our analysis, and looking at actual emissions from electricity installations in 2009 as shown in Figure 16 above (300Mt), we think our imputed number of 296Mt in Figure 17 tallies very well, and that our assumed generic thermal-efficiency rates are therefore very much in the right area. For fixed costs, we assume €45/kW for lignite plant, and €40/kW for both coal and OCGT stations.

Figure 17: Key inputs and assumptions for our stylized analysis of the impact of full EUA auctioning

	Lignite	Coal	Gas (OCGT)
Actual 2009 output (TWh)	143	108	60
Assumed generic thermal-efficiency rate	33%	36%	37%
Imputed emissions (Mt)	165	99	32
Assumed 2012 forward power price (€/MWh)*	52	52	63
Assumed fixed costs (€/kW)	45	40	40
Assumed fuel costs in 2012 (€/MWh)	7	32	60
CO ₂ forward price for 2012 (€/tonne)	15.5	15.5	15.5
Proportion of EUAs operators must buy in 2012	40%	40%	40%

Source: RWE, Deutsche Bank; *As with our analysis of the evolution of fossil-fuel clean spreads above (see Figures 10-12 and accompanying text), we here calculate the profitability of the different plant types on the assumption that lignite and coal plants receive the baseload price and gas generators the peakload price.

The next step in our analysis is to compare these 2009 levels of output and emissions against the forward curves for 2012 in order to gauge what the implied profitability of each fuel type would be if their respective levels of output and assumed emissions were the same in 2012 as they were in 2009. As a result, we make estimates for the generic fuel costs per MWh generated on the basis of the forward curves for 2012 (for lignite we assume a flat €7/MWh), and then take the 2012 forward price for EUAs of €15.5/tonne.

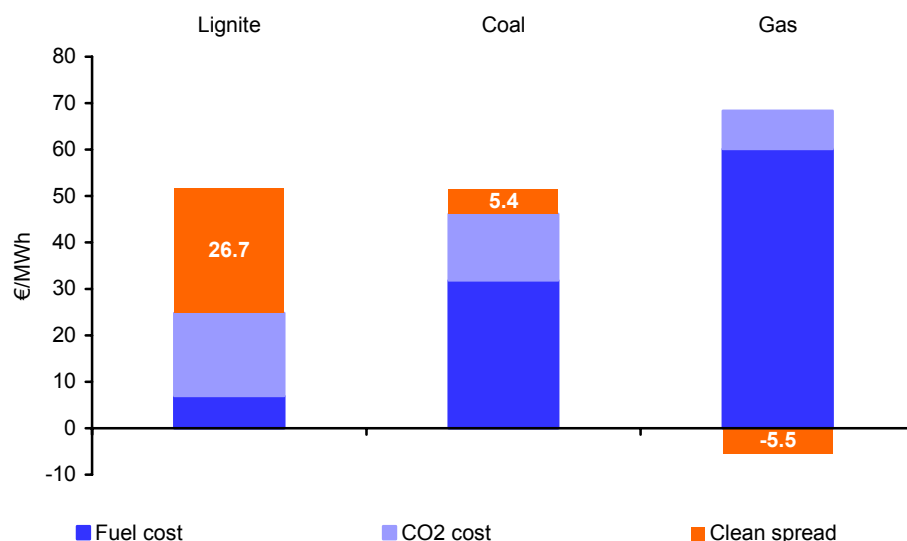
Figures 18-21 below then show four different ways of looking at the profitability of lignite, coal and gas plants using the inputs and assumptions set out in Figure 17.

We would emphasize upfront that this is only a stylized analysis, but it is one that nonetheless we think offers very useful insights into the sensitivity of the different fuel types to CO₂ prices and fixed costs.

Stylized clean spreads and real cash profits in 2012

First, Figure 18 shows our estimate for the clean spreads by fuel type for 2012 assuming the same level of output by each as in 2009 and the assumptions shown in Figure 17.

Figure 18: Stylized average clean spreads for lignite, coal, and gas* assuming 2009 output levels against 2012 forward curves (€/MWh)



Source: Deutsche Bank, * OCGT

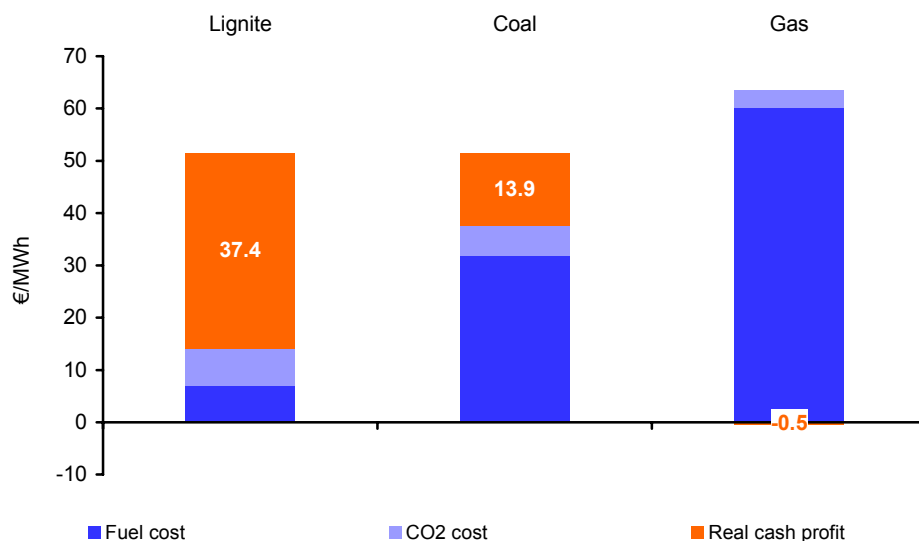
As can be seen, on this basis, lignite would have an average clean spread of €27/MWh, coal €5/MWh, but OCGT plant in fact a negative clean spread of -€6/MWh.

In reality, however, we estimate that generators will on average only have to pay for 40% of their allowances in 2012, and after adjusting for this the spread for each fuel type improves. This adjustment gives us the "real cash profit" per MWh generated.

As shown in Figure 19, on this basis we estimate that the real cash profit for lignite in 2012 would be €37/MWh, for coal €14/MWh, while OCGT plant would here be at break-even rather than loss-making.

In this way it can be seen that up until 2012 the profitability of fossil-fuel generators is in reality much better than is indicated by the clean spreads.

Figure 19: Stylized average real cash profits for lignite, coal, and gas* assuming 2009 output levels against 2012 forward curves with 60% free EUA allocations (€/MWh)



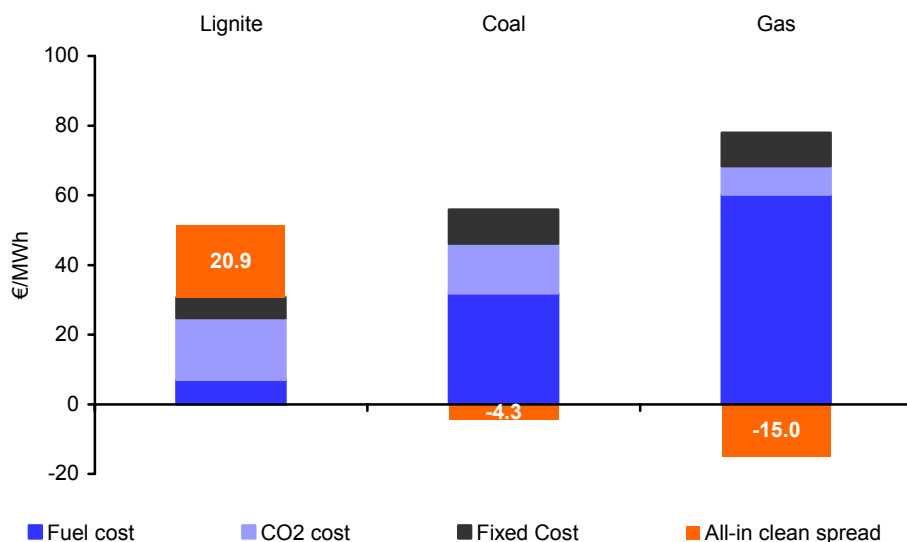
Source: Deutsche Bank, *OCGT

What happens, though, if we then introduce fixed costs into the equation?

Stylized all-in clean spreads and all-in real cash profits in 2012

Figures 20 and 21 below show our estimates of what we call “all-in clean spread” and the “all-in real cash profit” respectively for 2012, taking exactly the same assumptions as our previous calculations but adding in the extra element of fixed costs per MWh generated.

Figure 20: Stylized average all-in clean spreads for lignite, coal, and gas* assuming 2009 output levels against 2012 forward curves (€/MWh)



Source: Deutsche Bank, *OCGT

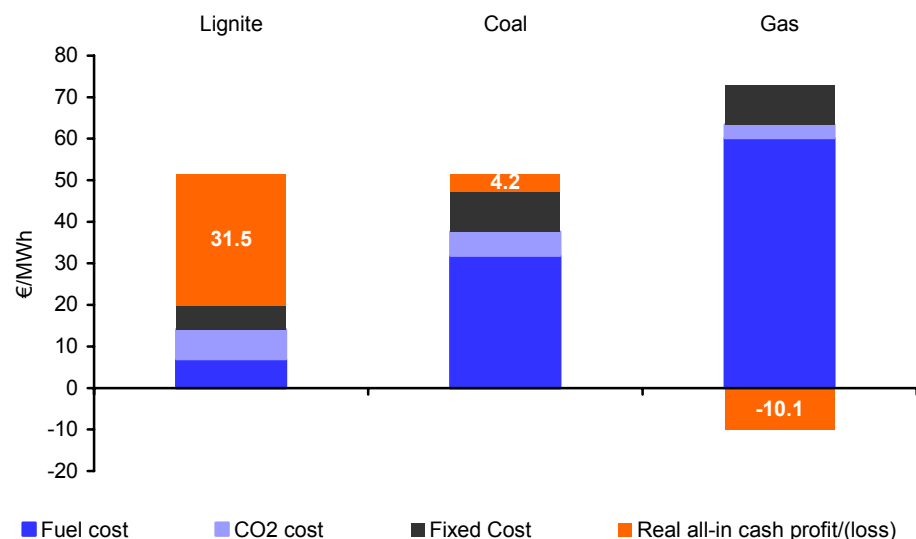
Thus, Figure 20 shows the clean spread adjusted for the fixed costs that we have assumed by fuel type on the basis of generic costs per kW of capacity and the load factors actually recorded in 2009.

In other words, it shows our estimate of what the average total cash profit or loss would be per MWh generated by plant type if they were all paying for 100% of their EUAs (as they will be after 2012), and after taking into account the fixed operating costs.

Even on this basis, we calculate that lignite would on average be making a very healthy margin of €21/MWh, but coal would here be making a loss of -€4/MWh, and OCGT plant would be deep in the red with a loss of -€15/MWh.

Finally, looking at Figure 21, we can see the extent to which the free allocation of 60% of EUAs offsets fixed costs. Figure 21 is based on the same assumptions as Figure 20, but adjusts for the fact that in reality in 2012 fossil-fuel generators will still be receiving on our estimates 60% of the EUAs they need for compliance obligations free of charge.

Figure 21: Stylized average all-in cash profit/(loss) for lignite, coal, and gas* assuming 2009 output levels against 2012 forward curves with 60% free EUA allocations (€/MWh)



Source: Deutsche Bank, BOCGT

Interestingly, the value of these free EUAs to lignite generators would on our calculations more than offset their fixed costs, such that their average all-in cash profit on this basis would actually be higher than the average clean spread shown in Figure 18 above (€31/MWh compared with €27/MWh respectively). This reflects the fact (i) that lignite generators are the most CO2 intensive of the fossil-fuel plants, and (ii) that with very high coal prices relative to lignite prices, lignite generators are running at much higher load factors than coal at the moment, thus reducing their fixed costs per MWh generated.

For coal and OCGT generators, by contrast, the free allocations of EUAs would only partially offset the fixed operating costs. So, coal generators would here have an average all-in cash profit of €4/MWh (compared with an average clean spread of €5/MWh as shown in Figure 18), while OCGT plant would be making an average all-in cash loss of -€10/MWh (compared with the negative clean spread of -€6/MWh shown in Figure 18).

For coal the free allowances do in fact offset most of the fixed costs, but for OCGT plant the value of free EUAs is outweighed by the fixed cost per MWh of running at a 48% load factor.

Conclusion: full EUA auctioning will pose tough choices for coal and OCGT plant

Our stylized analysis indicates a continuing very positive outlook for clean lignite margins and all-in cash profits beyond 2012, but to a very difficult situation for coal and OCGT plant.

We think that while coal plants would still show a slightly positive clean dark spread beyond 2012, after taking into account their fixed costs would on average be looking at an all-in cash loss in the order of -€4/MWh based on current forward curves.

For OCGT plant, the situation is even worse, as our analysis suggests they are on average already making an all-in cash loss even with an assumed free EUA allocation at 60% of their compliance obligation, and that this would increase to an average all-in cash loss in the order of €15/MWh after the move to full auctioning in 2013.

From all of this we conclude that lignite generators will continue to run their plant at very high load factors beyond 2012, but that the owners of hard-coal and OCGT capacity will have to think much more seriously about whether it is actually worth keeping older, less efficient plants open.

Conclusion: something has to give

Our analysis in this section has shown that the outlook for incumbent hard-coal and OCGT generators is very bleak, and we think that sooner or later something will have to give. In this respect the trigger could be the move to full EUA auctioning from 2013, as in our view this will force the owners of coal and gas-fired plant to think about shutting down more of their old capacity than they ordinarily would do based purely on standard operating lives.

In other words, given the current outlook for incumbent coal and gas-fired capacity, a mothballing/closure strategy for such plants might be the only way of bringing prices and margins for Germany's fossil-fuel fired generators back to acceptable levels over the next four to five years.

How much older coal and gas plant might ultimately need to be closed to restore the outlook for prices and margins will ultimately depend on three main factors:

- (i) the pace of the recovery in demand;
- (ii) whether Germany's nuclear power stations are indeed extended in line with the legislation recently passed in the *Bundestag*; and
- (iii) how much total new capacity – both fossil-fuel fired and renewable – comes on line over the next four years.

With this in mind, we now turn to an analysis of all these variables in Section 2 below, with a view to assessing the outlook for capacity margins by the end of 2014.

Having thus outlined our base case for capacity margins by year-end 2014, we will then be able in Section 3 to analyze what the forward curve is currently pricing in as far as closures and new build is concerned.

In turn, that will then enable us to analyze how much more aggressive than our base-case scenario any mothballing/closure strategy for coal and gas plants would have to be in order to restore healthier margins to incumbent generators.

2. The outlook for capacity margins to 2014

In this section we set out our base-case analysis of the evolution in capacity margins over 2010-14. At the end of 2009 net capacity stood at 153.8GW, but de-rated capacity for the winter of 2009/10 – i.e. the level of capacity reliably available to meet transmission-peak demand – was around 92GW. With our estimate for peak demand for 2010 at 75GW, we calculate the de-rated capacity margin of 22%. The question is, what will this look like by 2014?

To answer this question we here consider (i) the outlook for demand over our forecast period, (ii) the revised legislation on nuclear power plants, (iii) the prospects for fossil-fuel plant closures and new entrants, and (iv) the extent to which the Government's indicative trajectory for additional renewable capacity out to 2014 is likely to be achieved.

As far as demand is concerned, we expect a rebound of 3.5% in 2010 to 532TWh, followed by a more modest trend growth rate of 0.75% per year thereafter, while following the recently passed revised legislation on the operating lives of Germany's nuclear plants, our base-case scenario assumes that they will collectively now run for an average extra 12 years.

In terms of the prospects for net changes to fossil-fuel capacity over the next four years, we expect significant activity with regard to both closures and new entrants. Based on generic operating lifetimes of 45 years for coal and lignite stations, 30 years for CCGTs and 40 years for other fossil-fuel plant, we see potential for 17.6GW of closures by the end of 2014, against which we expect 12.1GW of new capacity to come on-stream over the period.

Although there is a lot more planned new fossil-fuel plant at the pre-approval stages, we do not think it is reasonable to assume that any of that will be up and running before 2015, as 10.6GW has already been postponed or cancelled owing to the fact that forward prices and margins are well below new-entrant levels. Overall, this means that we are actually expecting a net decline in fossil-fuel capacity by 2014 of 5.5GW.

With regard to the new renewable capacity that could be on the system by 2014, we expect a very significant increase of 27GW over the period, 21 GW of which will in our view be solar capacity, and the rest a broadly even mix between onshore wind, offshore wind, and bio-mass. The outlook here is much more positive than for fossil-fuel fired capacity because the investment decision for renewable projects is independent of wholesale prices, depending instead primarily on the level at which the feed-in-tariffs are set.

Putting all of this analysis together, our base-case scenario projects a net increase in total installed capacity by 2014 of 22GW. However, as all of this net increase is attributable to renewable capacity with much lower availability levels than fossil-fuel plants, the de-rated capacity margin actually declines over our forecast period, to 12% by 2014/15 against our assumed starting point of 22% in 2009/10.

The starting point: demand and capacity margins in 2009/10

Figure 22 shows the actual installed capacity in December for the German system in 2008 and 2009. The figures shown are net capacity, i.e. after taking off power used by the station itself. This capacity includes generation serving on-site demand by industrial users and small scale generation connected to the local distribution networks.

As a result, not all of this capacity can be used to cover peak demand on the transmission network. It should also be noted that although we have presented the gas capacity as 'CCGT' and 'other gas', the actual situation in Germany is more complex than this with many different types of station. New gas stations may be standard modern combined-cycle gas turbines. However there are also many older stations with steam and gas turbines, and often elements of heat production. The CCGT figure therefore does not all represent modern, high-efficiency plant.

Figure 22: Estimated installed German capacity (MW)

Capacity (end December)	2008	2009
Hydro	4,200	4,200
Pumped storage	6,200	6,200
Nuclear	20,452	20,452
Lignite	20,803	20,803
Coal	28,245	28,245
Oil	6,167	6,167
Other gas	12,767	12,467
CCGT	14,756	14,756
Onshore wind	23,897	25,762
Offshore wind	0	15
Bio-mass	3,973	4,429
Waste	1,440	1,460
PV	5,877	8,877
Geothermal	7	7
Total	148,785	153,841

Source: BDEW, BMWi, Deutsche Bank

At the end of 2009 total capacity stood at 153.8GW. After stripping out embedded generation, we estimate that this leaves around 139GW of capacity to cover the transmission peak demand for the winter of 2009/10. This must be adjusted downward further to remove unusable capacity (including much of the renewable capacity such as solar and wind, which may not be available at peak), capacity offline for outages and maintenance, and capacity needed to cover system service reserves.

As shown in Figure 23, for 2009/10 we estimate that around 92GW of reliably available capacity was available to cover peak demand (on the transmission network) of about 75GW. This gives a de-rated capacity margin of 22%. This degree of spare capacity explains why Germany is a net exporter at peak times at the moment.

Figure 23: Estimated de-rated capacity margin for 2009/10 (MW)

Capacity margin	2009/10
Net capacity at peak	139,007
Not usable capacity	33,314
Maintenance and overhauls	3,614
Outages	4,170
System service reserves	5,893
Unavailable capacity	46,992
Reliably available capacity	92,015
Peak load	75,555
Derated margin	22%

Source: Deutsche Bank

With the starting point for our analysis thus established, the question now is how capacity margins will develop over 2011-14. To answer this question, we need to examine the outlook for demand and net capacity changes over the next four years.

The recovery in demand will likely slow beyond 2010

According to BDEW figures cited by Bloomberg, electricity consumption in H1 2010 was 274TWh versus 262TWh in H1 2009, an increase of 4.5%. This would imply full-year demand in the region of 535TWh, a healthy increase on 2009 but still below the 2007 number.

However, the recovery in electricity demand in Germany has been helped by the strength of Germany's industrial sector, in turn a beneficiary of a weaker Euro boosting exports.

The recovery in demand has not been as strong in other large EU countries, and the risk is that continuing macro uncertainty in southern EU Member States and the more recent strength in the Euro versus the US dollar will lead to a reduction in the rate of demand recovery in Germany in H2 2010 and beyond.

Accordingly, we prefer to take a cautious approach to modeling future demand growth out to 2014, and assume an increase of 3.5% for the full year 2010, followed by a compound annual growth rate of 0.75% thereafter.

As shown in Figure 24, total end-user demand grows from 514TWh in 2009 to 548TWh in 2014. Required generation is higher given the need to cover losses. In addition further generation will be needed to cover pumping for the pumped-storage hydro stations, and for net exports. Peak demand rises to 78.4GW by 2014/15, though this is still slightly less than the 78.5GW seen in 2007.

Figure 24: DB base-case evolution in total and peak demand in Germany, 2009-14

	2009	2010	2011	2012	2013	2014
Total demand (TWh)	514.0	532.0	535.9	540.0	544.0	548.1
Implied total net generation (TWh)	538.9	557.8	561.9	566.2	570.4	574.7
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Peak demand (MW)	75,555	76,122	76,693	77,268	77,847	78,431

Source: BDEW, BMWi, Deutsche Bank

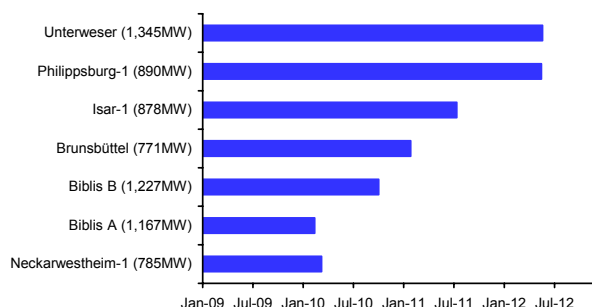
In order to assess the implications of this demand profile for capacity margins, we then need to analyze the outlook for nuclear operating-life extensions, fossil-fuel plant closures and new entrants over this period, as well as the prospects for additional renewable capacity.

Accordingly, we now turn to a detailed examination of these points below before drawing out the implications of all of our demand and supply-side assumptions for capacity margins out to 2014 in the concluding part of this section.

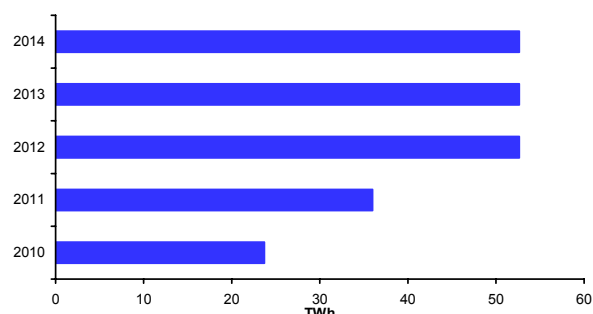
The nuclear reprieve would prevent the loss of 7GW by 2014

In April 2002 Germany's amended Atomic Energy Act (AEA) entered into force mandating the closure of all nuclear power plants by 2022. Under this legislation, Germany's entire remaining nuclear capacity was to be gradually phased out by 2022 on a schedule determined in accordance with a defined amount of allowed output per station. In line with this law, of the total 20.5GW of nuclear capacity available in Germany today, 7.1GW was due to close over 2010-14.

Figures 25 and 26 show what this would have meant in terms of lost capacity and lost annual output from these stations over 2010-14.

Figure 25: Nuclear capacity that would have been lost over 2010-2014 under previous legislation

Source: Deutsche Bank

Figure 26: Annual nuclear output that would have been lost over 2010-14 under previous legislation (TWh)

Source: Deutsche Bank

However, in early September of this year the CDU/CSU/FDP Government agreed amendments to the 2002 AEA, and these were then ratified by the lower house of Parliament (the *Bundestag*) in late October. These changes will enable German nuclear plants to run for an extra 12 years on average, and our estimate of the revised closure schedule for each of these stations is shown in Figure 27 (stations built before 1980 receive an average extension of eight years, those built after this date one of 14 years).

Figure 27 shows that whereas under the previous legislation there would only have been four stations operating by 2020, under the revised legislation all of these plants could still be running by that date, with the last one not coming off until as late as 2037.

Figure 27: Nuclear power plants in Germany: DB revised expected phase-out dates

Power Plant	Owner	Chronological order of phase-out	Capacity per power plant (MW)	Previous assumed date of shut-down	Revised assumed date of shut-down
Stade	EON:66.7% / Vattenfall:33.3%	1	640	11/14/2003	11/14/2003
Obrigheim	EnBW:99.8% / Deutsche Bahn:0.2%	2	340	05/11/2005	05/11/2005
Neckarwestheim-1	EnBW:99.8% / Deutsche Bahn:0.2%	3	785	02/13/2010	02/13/2018
Biblis A	RWE	4	1,167	03/10/2010	03/10/2018
Biblis B	RWE	5	1,227	10/04/2010	10/04/2018
Brunsbüttel	Vattenfall:66.7% / EON:33.3%	6	771	01/29/2011	01/29/2019
Isar-1	EON	7	878	07/15/2011	07/15/2019
Philippsburg-1	EnBW:99.8% / Deutsche Bahn:0.2%	8	890	05/19/2012	05/19/2020
Unterweser	EON	9	1,345	05/23/2012	05/23/2020
Grafenheinfeld	EON	10	1,275	04/09/2015	04/09/2029
Gundremmingen B	RWE:75% / EON: 25%	11	1,284	04/17/2016	04/17/2030
Gundremmingen C	RWE:75% / EON: 25%	12	1,288	03/22/2017	03/22/2031
Krümmel	Vattenfall:50% / EON:50%	13	1,346	12/29/2017	12/29/2031
Philippsburg-2	EnBW:99.8% / Deutsche Bahn:0.2%	14	1,392	11/15/2018	11/15/2032
Grohnde	EON:83.3% / SW Bielefeld:16.7%	15	1,360	03/02/2019	03/02/2033
Brokdorf	EON:80% / Vattenfall:20%	16	1,410	02/07/2020	02/07/2034
Isar-2	EON:75% / SW München:25%	17	1,400	03/18/2021	03/18/2035
Emsland	RWE:87.5% / EON:12.5%	18	1,329	03/12/2022	03/12/2036
Neckarwestheim-2	EnBW:99.8% / Deutsche Bahn:0.2%	19	1,305	07/11/2023	07/11/2037

Source: RWE, Deutsche Bank

The Government has a majority in the *Bundestag* so securing the votes for the proposed changes was not a problem. However, it does not have a majority in the upper house of parliament (the *Bundesrat*), and although the Government takes the view that the *Bundesrat*'s approval is not required to change the 2002 amended AEA, the SPD and Green opposition parties, as well as some of Germany's federal states (*Länder*), take a different view.

As a result, the question of whether the *Bundesrat*'s approval is also required or not could soon be the subject of a legal case, as opposition parties have said that they will ask the Constitutional Court to rule on this question if the Government does not submit it to the *Bundesrat* after the *Bundestag* vote. Given that the Government does not intend to do this, a legal challenge to the Government's authority to make these changes now seems very likely.

In addition to the legal uncertainty that is now likely to arise, there is the political uncertainty caused by the fact that the SPD and Greens have said that if they win the next federal election due in 2013 they will revoke the lifetime extensions just granted.

Finally, the economics of the lifetime extensions are uncertain too. This is because in return for granting the extensions the Government has placed material financial conditions on the owners of the plants, and the precise impact of these conditions is not yet measurable on a plant-by-plant basis. This is because although the impact of the nuclear-fuel tax payable until 2017 and the annual levy payable into a fund for renewables thereafter can both be calculated, the Government has not yet given details about the capex requirements for safety upgrades for individual stations (other than to say that these will not exceed €500m for any single plant).

All of these uncertainties mean that it is still unclear whether all of these plants will in fact end up having lifetime extensions, as the owners might ultimately take a general view that the legal and political risk is too high to justify the extra upfront financial burden that comes with the extensions. Alternatively, if they are ultimately comfortable on a general basis with the legal and political risk, they might decide that specific plants are not worth extending for the extra capex entailed in upgrading them to higher safety standards.

Despite all these uncertainties, however, we continue to take the view first articulated in our report *A New Look at New Entrants* of 18 January 2007, namely that lifetime extensions for all of Germany's nuclear plants with a contribution from the owners in return to go to financing alternative low-carbon power-generation technologies would be the best policy outcome.

Accordingly, whilst acknowledging the uncertainty that will surround the question of lifetime extensions for some time to come, our base-case scenario in this report is that the legislation already passed in the *Bundestag* last month will ultimately result in extensions for all of these plants in accordance with the revised shutdown schedule we have indicated in Figure 27.

This is obviously a key assumption in our modeling of German power prices and spreads out to 2014, as with no need to replace the 7GW of capacity and nearly 60TWh of annual baseload output that would otherwise have disappeared by 2014 there might be more fossil-fuel plant closures and fewer new entrants than would have been the case under the previous legislation.

With this in mind, we turn next to a consideration of potential fossil-fuel closures out to 2014.

Closures: 17.6GW of fossil-fuel capacity potentially gone by 2014

Figure 28 shows our estimate of the profile of closures for fossil-fuel plants made out to 2014 assuming generic operating lives. We assume an operating life of 45 years for coal and lignite

stations, 30 years for CCGTs and 40 years for other gas stations and for oil capacity. Where stations have been repowered we assume at least a further 10 years of operation. For very old stations we assume closure is spread over the next 4 years rather than immediately. On this basis, we calculate that 17.6GW of fossil-fuel capacity would be disconnected by the end of 2014.

Figure 28: Capacity loss from expected closures in fossil-fuel power plants over 2011-14 (MW)

	Lignite-fired plants	Coal-fired plants	Gas-fired plants	Oil-fired plants	TOTAL
2011	-555	-322	-1,876	0	-2,753
2012	-642	-577	-3,452	-94	-4,765
2013	-1,018	-1,136	-909	-386	-3,449
2014	-1,355	-1,926	-2,088	-1,264	-6,633
TOTAL	-3,570	-3,961	-8,325	-1,744	-17,600

Source: DENA, Deutsche Bank

Estimating the timeframe for plant closures in this way has the advantage of simplicity, but it ignores the practical considerations that will actually be decisive in the decision-making process. In this respect, there are in our view five key considerations:

(i) What will be the impact of full EUA auctioning on the fossil-fuel generators' cash margins from 2013?

As already explained in Section 1 above, until 2012 German fossil-fuel generators in aggregate receive c.60% of their EUAs free of charge, and hence an extra cash benefit per MWh generated beyond that indicated by the gross margin. From 2013, however, they will have to pay for 100% of their allowances, and this will impact lignite, coal, gas, and oil generators in different ways.

(ii) Whether the Government's plans for nuclear-lifetime extensions proceed as planned

As just explained, our base-case scenario assumes that it will, but if it does not older fossil-fuel plants might stay open for longer and more new build might go ahead than we assume below.

(iii) How much total new capacity will be built over this period?

Depending on how much new plant is built, it could be more or less attractive to keep older plant open beyond a standard operating life, or to accelerate its closure ahead of the standard operating life.

(iv) What will be the breakdown of this new capacity (i.e. how much will be baseload fossil-fuel plant, how much mid-merit/peakload, how much must-run renewable capacity, etc.)?

New plant of a given kind entering the merit order will affect existing plant in different ways, but the permission to build new capacity is also sometimes contingent upon the closure of existing plant of the same kind. For example, as a permitting condition for its new 2.1GW lignite plant at Neurath, RWE gave an undertaking to close at least ten 150-MW units at three other lignite stations, Frimmersdorf, Niederaussem, and Weissweiler.

(v) How will fossil-fuel generators' margins develop over the next four years under different commodity-price scenarios?

Depending on the level and outlook for commodity prices it might be more or less attractive to keep certain fossil-fuel plants open beyond their normal expected operating lives while accelerating the closure of others.

Having already analyzed points (i) and (ii) above, we next examine points (iii) and (iv) in the following two sub-sections below respectively, while in Section 3 we compare our on projections for commodity prices out to 2014 with the forward curves shown in Section 1 above.

After setting out our views on all of these variables we will then be able – again in Section 3 – to run sensitivity analyses against the profile for closures shown in Figure 28 with a view to ascertaining (i) what the forward curves are currently pricing in on closures, and (ii) what level of closures might actually be necessary to restore healthy margins for coal and gas-fired generators. For the time being, however, the numbers shown in Figure 28 serve as a very good reference point for an initial estimate of the amount and profile of capacity that could come offline by 2014.

The next question is, how much new fossil-fired capacity is likely to come onstream by 2014?

New build: we expect 12.1GW of new fossil-fuel plant by 2014

Before looking at the list of planned new fossil-fuel power plants in Germany, Figure 29 sets out our estimates of the long-term power prices required for new CCGT and coal-fired plant. This is because the prospects for further new build above and beyond the plants already under construction will depend to a very great extent on the gap between current forward prices and new-entrant prices, and the time it takes for this gap to close.

Figure 29: Estimated new-entrant costs for power plants with EUAs at €20/t

	CCGT	Conventional coal Plant
Capital cost	€750,000/MW	€1,900,000/MW
Capacity	1,000MW	1,000MW
Capital outlay	€750m	€1,900m
Required return (pre-tax real)	9.6%	9.6%
Fuel Price	€8.2/GJ	€ 3.6/GJ
	Efficiency rate 58%	Efficiency rate 47%
	€51/MWh	€27.2/MWh
Fixed operating costs	€18/kw	€ 37/kw
Variable operating costs	€0.2/MWh	€0.6/MWh
Carbon price	€20/t	€20/t
Carbon intensity	0.35	0.72
Load factor for first 20 years	86%	86%
Annual output for first 20 years	7.5TWh	7.5TWh
Load factor for remaining 20 years	40%	40%
Annual output for remaining 20 years	3.5TWh	3.5TWh
Power price necessary to earn required return	€70/MWh	€73/MWh

Source: Deutsche Bank, RWE, E.ON

As a result, our estimate of new-entrant costs is a key driver of our assumptions regarding how much of the potential new capacity not yet under construction will actually be built by 2014.

We would highlight that the fuel price we have assumed for a CCGT generator takes the average implied gas price for an oil-indexed contract at \$85/bbl and \$100/bbl, which comes to €8.2/Gigajoule.

We do this because we think any developer looking to build a new CCGT plant with an expected lifetime of 40 years would want to be comfortable with a scenario of higher long-term oil prices than current levels.

For coal, we assume a long-run price of \$125/t, which equates to €3.6/GJ, while the carbon price we here assume of €20/t is our fundamental fair value for EUAs for 2011.

On this basis we derive a long-run marginal cost for a new baseload CCGT plant of €70/MWh, and for a new coal-fired plant of €73/MWh, but it is probably more realistic to think of these prices in terms of ranges. For a CCGT plant we think a range of €65-70/MWh is reasonable, and for coal €70-75/MWh.

Against this backdrop, what is the current status of new-build projects in Germany?

Figure 30 shows the planned new capacity in Germany either already under construction or approved for construction. Our source for this data is the *Platts* publication *Power in Europe* (Issue 583, September 2010), which to our knowledge provides the most comprehensive survey and updates on planned new capacity across the EU.

Figure 30: German fossil-fuel power plants under construction or approved

Location	Estimated capacity (MW)	Type	Potential start date as given by Platts	DB estimated start date*
UNDER CONSTRUCTION				
Spreetal, Cottbus	56	CCGT	Q1 2010	Q12010
Lingen, Emsland	875	CCGT	April 2010	April 2010
Walsum – Unit 10, Duisburg	750	Coal	Q3 2010	Q3/Q4 2010
Plattling, Bavaria	115	CCGT	August 2010	August 2010
Irsching 5, Ingolstadt	860	CCGT	May 2010	May 2010
Irsching 4, Ingolstadt	530	CCGT	2011	2011
Boxberg, Saxony	675	Lignite	Q1 2011	Q1 2011
Lingen, Emsland	232	CCGT	Q1 2011	Q2 2011
Braunschweig	76	CCGT	Q1 2011	Q2 2011
Neurath, Rheinland-Pfalz	2,100	Lignite	Mid/late 2011	Mid/late 2011
Heizkraftwerk Nord, Bonn	95	CCGT cogen	Late 2011	Q1 2012
Lunen, West Rhine Westphalia	750	Coal	Q4 2012	Q4 2012
Rheinhafen (RDK8), Karlsruhe	912	Coal	2011/12	2012
Westfalen, Hamm-Uentrop	1,600	Coal	Q4 2012/ Q1 2013	Q1 2013
Wilhelmshaven	800	Coal	Q4 2012	2013
Moorburg, Hamburg	1,640	Coal/CHP	2013	2013
Datteln 4	1,100	Coal	2011	UNCERTAIN
TOTAL under construction	13,166			
APPROVED				
Lubmin, Mecklenburg-Vorpommern	1,200	CCGT	2011	ON HOLD
Bocholt Power, NRW	420	CCGT	2012	Not before 2015
TOTAL approved	1,620			

Source: Deutsche Bank from Platts; *the dates in this column are those by which we think it is realistic to assume the plant in question will be online

The capacity of the plants under construction comes to 13.2GW, and that of those approved but awaiting construction 1.6GW. Of the 13.2GW under construction, we estimate that 2.7GW either already has or will begin commercial operation this year (shown in blue in Figure 30).

Of the 13.2GW under construction/already operational, 7.6GW is hard-coal capacity (of which 1.6GW CHP), 2.8GW lignite, and 2.8GW of CCGT (Figure 31).

Figure 31: New fossil-fuel capacity either built, under construction, or approved

Fuel source	Capacity (MW)	% of total
Hard coal	5,912	44.9
Coal CHP	1,640	12.5
Lignite	2,775	21.1
CCGT	2,839	21.6
TOTAL	13,166	100

Source: Platts, Deutsche Bank

We expect all of this capacity under construction to be on the grid by 2013 with the possible exception of Datteln, which has run into legal difficulties with its permitting and where, according to Platts, construction has been suspended. Unless and until this legal problem is resolved we do not think it possible to give an estimated start date.

Looking then at the 1.6GW of capacity approved and awaiting construction, the larger of the two – a 1,200MW CCGT plant at Lubmin – has recently been put on hold by E.ON, and we do not think either of these plants will be on the grid by 2014.

Datteln and Lubmin respectively illustrate the two big difficulties facing any major new fossil-fuel construction project in Germany today:

- (i) increasingly difficult location issues (public protests in Germany against new coal power plants in particular have increased markedly in the last couple of years);
- (ii) as mentioned in Section 1 above and demonstrated by our analysis of new-entrant costs shown in Figure 29, forward baseload prices and clean dark/spark spreads are currently well below new-entrant cost levels for both coal and gas.

As a result of these two factors, it is no surprise to find that a large amount of proposed new fossil-fuel capacity at earlier stages of the planning and development process has been either suspended or abandoned altogether over the last 18 months.

Figure 33 on the next page shows the planned new capacity at the pre-approval stage of development, and what is striking is the amount of this potential new build that has been either postponed or cancelled in the last 12-18 months (9.4GW, as highlighted in blue in Figure 33).

This breaks down as 7.7 GW of hard-coal capacity (of which 820MW CHP), 450MW lignite, and 2.5GW of CCGT. Adding E.ON's already approved 1,200MW CCGT plant at Lubmin to this list means that a total of 10.6GW has been postponed or cancelled in the last 18 months (Figure 32).

Figure 32: Planned new fossil-fuel capacity postponed or cancelled in last 18 months

Fuel source	Capacity (MW)	% of total
Hard coal	6,875	64.9
Coal CHP	820	7.7
Lignite	450	4.2
CCGT	2,450	23.1
TOTAL	10,595	100

Source: Platts, Deutsche Bank

This demonstrates just how difficult it is to justify building both coal and gas-fired plants in the current environment for forward prices and spreads highlighted in Section 1 above compared with the required new-entrant costs shown in Figure 29.

Figure 33: Planned new generation capacity in Germany at early stages of development

Location	Estimated capacity (MW)	Type	Potential online date as given by Platts	DB estimated start date*
APPLIED BUT ON HOLD				
Eisenhüttenstadt, Brandenburg	800	CCGT	ON HOLD	Not before 2015
OTHERS PROPOSED BUT ON HOLD OR ABANDONED				
Ingelheimer Aue, Mainz	820	Coal CHP	ON HOLD	Not before 2015
Griesheim, Frankfurt am Main	450	CCGT	ON HOLD	Not before 2015
Hurth, Cologne, North Rhine Westphalia	450	Lignite IGCC + CCS	ON HOLD	Not before 2015
Niehl, Cologne	775	Coal	ON HOLD	Not before 2015
Herne 5	750	Coal	ON HOLD	Not before 2015
Dorpen, Lower Saxony	900	Coal (CHP?)	ABANDONED	n/a
Griefswald (Lubmin), Mecklenburg Vorpommern	1,600	Coal	ABANDONED	n/a
Stade, Lower Saxony	800	Coal, gas	ABANDONED	n/a
Wilhelmshaven	500	Coal	ABANDONED	n/a
Kiel	800	Coal	ABANDONED	n/a
Dortmund**	750	Coal	ABANDONED?	n/a
TOTAL ON HOLD or ABANDONED	9,395			
APPLIED				
Mittelsbüren, Bremen	420	CCGT	Q2 2013	Not before 2015
PROPOSED				
Rheinhafen (RDK8), Karlsruhe	460	CCGT	?	Not before 2015
Stade	800+200	Coal+gas	2012	Not before 2015
Niehl, Cologne	Up to 1,200	CCGT	2012?	Not before 2015
Brunsbüttel	1,800	Coal	2013	Not before 2015
Staudinger (Grosskrotzenburg), Hesse	1,100	Coal	2013	Not before 2015
Premnitz, Berlin	400	CCGT/CHP	2013	Not before 2015
Lunen	750	Coal	Q3 2013	Not before 2015
Ludwigsau, Hessen	1,100	CCGT	Q4 2013	Not before 2015
Brunsbüttel	800	Coal – CHP?	2014	Not before 2015
Sckopau	800	CCGT	2014	Not before 2015
Leverkusen	430	CCGT	2014	Not before 2015
Mannheim, Block 9	900	Coal CHP	2013	Not before 2015
Lausward, Dusseldorf harbour	400	Gas CHP	End 2014	Not before 2015
Frankfurt	1,100	Coal	2014/15	Not before 2015
Jaenschwalde	250	Lignite	2015	Not before 2015
Jaenschwalde	500	Lignite CCS	2015	Not before 2015
Wustermark, Brandenburg	1,200	CCGT	2015	Not before 2015
Krefeld-Uerdingen, NRW	750	Coal cogen	2015	Not before 2015
Profen, Saxony Anhalt	660	Lignite	2015	Not before 2015
Klingenberg, Lichterfelde, Berlin	580	CCGT	2015	Not before 2015
Hamm	400-500	CCGT	?	Not before 2015
PRE-PROPOSAL				
Duisburg-Wanheim	120	Gas CHP	End 2012	Not before 2015
Bestenheid industrial estate, Wertheim?	350	Gas or coal	2013/14	Not before 2015
TOTAL applied, proposed, and pre-proposed	17,520			

Source: Deutsche Bank from Platts; *Given the current forward baseload-power curve and clean dark/spark spreads, we do not think that it is reasonable to assume that any of these plants will be onstream before 2015; **Issue 548 of Platts Power in Europe tracker included this station as being at the pre-proposal stage but the latest edition makes no reference to it, so we assume that it has been abandoned.

For lignite, the two plants already under construction shown in Figure 30 above were premised on the German Government's initial plan in 2006 to award all new fossil-fuel plants starting up over 2008-12 free EUAs for the first 14 years of their operating lives.

This plan was subsequently rejected by the European Commission, and with the ETS cap tightening over time we think that new lignite plant will henceforth only be viable if it comes fitted with CCS. However, CCS technology is still in the early stages of development such that they are only going ahead at the moment with EU or national-government funds.

In short, in light of the planned nuclear extensions and the depressed forward curve for prices and spreads, we think there will be many more postponements and cancellations of planned new build over the next 12-18 months.

Indeed, although much of the postponed and planned new capacity shown in Figure 33 may ultimately be built, we do not think any of it will be generating electricity before 2015.

As a result, we assume that the total amount of new fossil-fuel capacity built by 2014 will be 12.1GW (i.e. the 13.2GW shown in Figures 30 and 31 minus the 1.1GW at Datteln, which is now uncertain).

We see a net reduction in fossil-fuel capacity of 5.5GW by 2014

Putting together our assumptions on closures and new build, we derive the profile for net annual changes in fossil-fuel capacity shown in Figure 34.

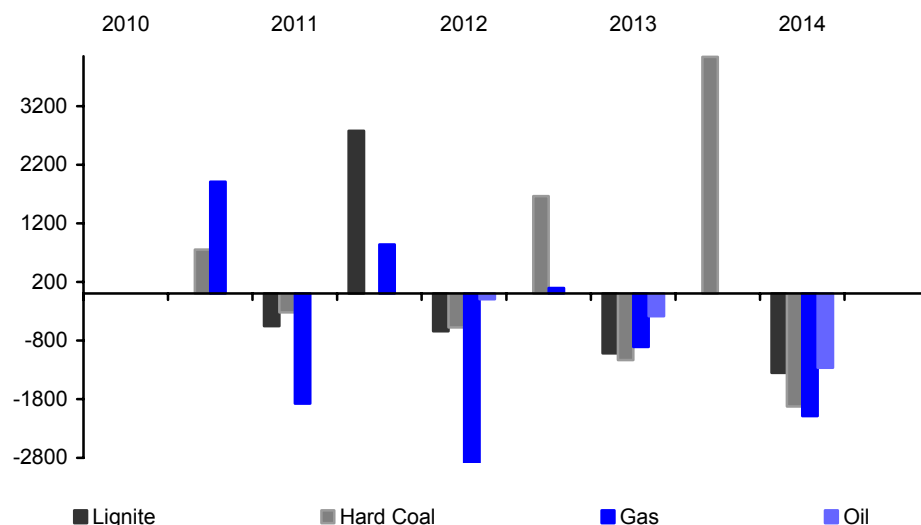
Figure 34: DB base-case annual change in net fossil-fuel capacity over 2010-14 by source (MW)

	2010	2011	2012	2013	2014	TOTAL
Lignite	0	+2,220	-642	-1,018	-1,355	-795
Coal	+750	-322	+1,885	+2,104	-1,926	+2,491
Gas	+1,906	+1,038	-3,357	-909	-2,088	-5,486
Oil	0	0	-94	-386	-1,264	-1,744
TOTAL	+2,656	+860	-2,208	-209	-6,633	-5,534

Source: Platts, Deutsche Bank

Overall, while we expect coal capacity to increase by 2.5GW on a net basis by 2014 (even without Datteln coming onstream by then), we expect lignite, gas, and oil capacity to decline over the period on a net basis such that in aggregate fossil-fuel capacity falls by 5.5GW.

Figure 35: DB base-case net changes to fossil-fuel capacity over 2010-14 (MW)



Source: Deutsche Bank

Figure 35 shows our assumed closures and additions by fuel type over the period.

However, we expect a significant amount of new renewable capacity to be built over the next four years.

New renewable capacity: we expect an extra 27GW by 2014

In line with its obligation under Directive 2009/28/EC (the Directive on the EU's renewable-energy target for 2020), Germany submitted its National Renewable Energy Action Plan (NREAP) in the early summer of this year. Germany's NREAP sets out an indicative trajectory for meeting the country's legally binding target of sourcing 18% of its final energy consumption from renewables by 2020, compared with 10% in 2009.

Ambitious targets for incremental renewable electricity capacity by 2014

For the electricity sector, Germany's indicative trajectory has renewables accounting for 39% of total power generated by 2020, compared with 16.4% in 2009. In absolute terms, this represents an increase to 217TWh of electricity generated from renewables by 2020, compared with 95TWh in 2009.

Figures 36 and 37 below set out the indicative trajectories for installed capacity and total generation from renewables respectively by 2020, broken down by the various sources of renewable electricity. We have highlighted in blue the actual levels in 2009, and the indicative target for 2014, which is our focus in this report.

Figure 36: Indicative trajectory for installed renewable-electricity capacity by source in Germany, 2010-20 (MW)

	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydropower	4,760	4,329	4,068	4,088	4,111	4,137	4,165	4,196	4,228	4,258	4,286	4,309
Onshore wind	25,762	27,526	29,175	30,566	31,672	32,763	33,647	34,371	34,815	35,188	35,479	35,750
Offshore wind	15	150	432	792	1,302	2,040	3,000	4,100	5,340	6,722	8,272	10,000
Biomass	5,949	6,312	6,620	6,934	7,214	7,475	7,721	7,976	8,211	8,440	8,648	8,825
Solar PV	9,800	15,784	20,284	23,783	27,282	30,781	34,279	37,777	41,274	44,768	48,262	51,753
Geothermal	7	10	17	27	40	57	79	107	142	185	236	298
Total	46,293	54,111	60,596	66,190	71,621	77,253	82,891	88,527	94,010	99,561	105,183	110,935

Source: German Government, Deutsche Bank; *Actual numbers for 2009

Figure 37: Indicative trajectory for renewable-electricity production by source in Germany, 2010-20 (GWh)

	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydropower	19,147	18,000	18,000	18,000	19,000	19,000	19,000	19,000	19,000	19,000	20,000	20,000
Onshore wind	38,542	44,397	48,461	51,152	54,064	58,420	61,990	64,583	66,873	68,913	70,694	72,664
Offshore wind	38	271	959	1,903	3,250	5,237	8,004	11,484	15,592	20,297	25,666	31,771
Biomass	30,441	32,778	34,682	36,710	38,562	40,359	42,090	43,729	45,299	46,761	48,133	49,457
Solar PV	6,578	9,499	13,967	17,397	20,293	23,218	26,161	29,148	32,132	35,144	38,243	41,389
Geothermal	19	27	53	97	164	257	377	534	730	976	1,281	1,654
Total	94,765	104,972	116,122	125,259	135,333	146,491	157,622	168,478	179,626	191,091	204,017	216,935

Source: German Government, Deutsche Bank; *Actual numbers for 2009

As can be seen, total installed renewable capacity by year-end 2009 was 46.3GW, and the total amount of electricity generated from renewables in 2009 was 95TWh. According to the indicative trajectory, by 2014 installed capacity is expected to increase to 77GW and output to 146TWh.

Figure 38 breaks down the expected increase in renewable capacity by source by 2014 in both absolute and percentage terms, while Figure 39 breaks down the expected increase in production in the same way.

Figure 38: Government's indicative increase in renewable-electricity capacity by source in Germany, 2009-14 (MW)

	2009*	2014	Absolute increase (MW)	% increase
Hydropower	4,760	4,137	-623	-13.1
Onshore wind	25,762	32,763	7,001	27.2
Offshore wind	15	2,040	2,025	n/a
Biomass	5,949	7,475	1,526	25.7
Solar PV	9,800	30,781	20,981	214
Geothermal	7	57	50	n/a
Total	46,293	77,253	30,970	66.9

Source: German Government, Deutsche Bank; *Actual numbers for 2009

Figure 39: Government's indicative increase in renewable-electricity output by source in Germany, 2009-14 (GWh)

	2009*	2014	Absolute increase (MW)	% increase
Hydropower	19,147	19,000	-147	-0.8
Onshore wind	38,542	58,420	19,878	51.6
Offshore wind	38	5,237	5,199	n/a
Biomass	30,441	40,359	9,918	32.6
Solar PV	6,578	23,218	16,648	253
Geothermal	19	257	238	n/a
Total	94,765	146,491	51,705	54.5

Source: German Government, Deutsche Bank; *Actual numbers for 2009

As can be seen, the expected increases across all sources apart from hydro are very impressive, but in terms of capacity it is the solar sector that really stands out.

The Government's indicative projections see capacity increasing by 21GW over 2009-14 out of a total increase of 31GW, which accounts for two thirds of the total expected increase in renewable capacity over the period.

By contrast, in terms of production it is the onshore-wind sector that sees the biggest absolute increase, with output here expected to rise by 20TWh against 2009 levels out of a total projected increase of 50TWh. Solar posts the next largest increase in output under the indicative trajectory, up by nearly 17TWh over the period.

In terms of the load factors of the different sources (i.e. the level of output relative to total maximum potential output in a year), Figure 40 shows that hydro and bio-mass have by far the highest actual and implied yields in 2009 and 2014 respectively. However, the two sources expected to account for most of the renewable output by 2014 – onshore wind and solar – had the lowest actual load factors in 2009 and although the implied rates for both are higher by 2014, they are nonetheless expected to remain the lowest in 2014.

Figure 40: Actual and implied load factors for renewable sources, 2009 and 2014, under indicative trajectory

	Load factor in 2009*	Implied load factor in 2014	Change in percentage points
Hydropower	45.9%	52.4%	+6.5
Onshore wind	17.1%	20.4%	+3.3
Offshore wind	28.9%	29.3%	+0.4
Biomass	58.4%	61.6%	+3.2
Solar PV	7.7%	8.6%	+0.9
Geothermal	31.0%	51.5%	+20.5
TOTAL	23.4%	21.6%	-1.8

Source: German Government, Deutsche Bank; *Actual numbers for 2009

Indeed, owing to the very large increase in solar capacity and output by 2014 but its very low load factor, the overall load factor from renewables is actually expected to decline slightly under the indicative trajectory by 2014, to 21.6% from 23.4% in 2009.

The question is, how much of this incremental renewable capacity under Germany's indicative trajectory do we think it is reasonable to assume will actually be in place by 2014?

Renewable capacity is driven by feed-in tariffs independent of wholesale prices

As mentioned earlier, unlike new fossil-fuel plants, new renewable capacity in Germany is incentivized by feed-in-tariffs (FITs), which means that it receives a guaranteed price for its offtake and is therefore indifferent to the wholesale power price. This means that as long as the FIT is set at a high enough level to give the developers their required rate of return, attracting capital should not in and of itself be a constraint.

As a result, estimating the amount of new renewable capacity that is likely to be on the system by 2014 is to a large extent a question of gauging whether the FITs for the different renewable sources are attractive enough for investors. If this is the case, then we think it is reasonable to assume that the capital should in theory be available, and the question then becomes one of whether there are other factors that might impede the roll-out, such as supply-side bottlenecks.

Below we briefly examine the prospects for the three main sources of expected increases in renewable capacity under the Government's indicative trajectory: solar, onshore wind, and offshore wind.

Solar: we think the indicative trajectory to 2014 is achievable

Despite phased cuts to the solar FITs in Germany that have already seen reductions in July and October of this year with another one to come in January of 2011, our equity analysts (Alexander Karnick and team) remain cautiously optimistic about the prospects for incremental solar-capacity additions over 2010-14.

This is because although they project a decline in the average FIT from €0.37/kWh in H1 2010 to €0.31/kWh in H2 2010, to €0.28/kWh in H1 2011, they still see an attractive IRR on new investments even with the lower levels for FITs going forward (note that even the lower FIT of €0.28/kWh for H1 2011 is nearly six times higher than the 2011 forward wholesale baseload price of €0.05/kWh).

Accordingly, they expect new installations in 2010 to almost double to 7GW against last year (3.8GW were installed in 2009), and to remain at very high levels for 2011 and 2012 at 6.2GW and 6GW respectively. However, with lower visibility on FITs beyond this horizon and the risk that the industry's high rate of new installations will accelerate the reductions in tariffs further over time, their model has new installations falling to 4.5GW in 2013.

This means that our equity analysts project an increase in capacity by 2013 of 23GW, which is already ahead of the 21GW increase projected under the Government's indicative trajectory by 2014.

As a result, we think the 21GW expected under the indicative trajectory is achievable, and are therefore comfortable taking the profile of this projection as shown in Figure 34 above into our base-case scenario.

The indicative trajectories for onshore and offshore wind

Figure 41 shows the FITs for onshore and offshore wind under current rules.

Figure 41: Feed-in tariffs for wind electricity or other support schemes in Germany (€/MWh)

Support Schemes	Onshore Wind Power			Offshore Wind Power		
	Contract Duration	2009	2010	Contract Duration	2009	2010
Feed-in Tariff	5 first years	92.0	91.1	12 first years	130-150	130-150
Floor price	Year 6 to 20	50.2	49.7	Year 13 to 20	35	35

Source: Euroobserver, Deutsche Bank

The FIT for onshore wind is set at about €90/MWh for the first five years of a project, and is then floored at €50/MWh for the following 15 years, with developers receiving the wholesale price over this period if it is higher than the €50/MWh floor.

For offshore wind the FIT is set at €130-150/MWh for the first 12 years, and is then floored at €35/MWh for the following eight years, with developers receiving the wholesale price over this period if it is higher than the €35/MWh floor.

As explained in our report *Hard to Credit* (22 June 2010, see pages 37 and 38), we think the FIT level for onshore wind is still generous enough to cover project-development costs while giving an adequate rate of return, so financing in and of itself should not really be a constraint.

However, what is a big obstacle to the development of more onshore wind in our view is that the best sites have already been taken, such that most of the potential for further increases in onshore capacity over the next 10 years lies in re-powering existing windfarms.

The issue here, though, is that according to the German Wind Energy Association, re-powering generally only makes commercial sense after 15 or more years operating life for an existing facility when the turbines are at the end of their economic lives. This means that there will be very significant potential for increasing capacity via re-powering over the second half of this decade, but in our view only more limited opportunities before 2015.

Accordingly, we assume a lower rate of new installations for onshore wind over 2010-14 than the Government's indicative trajectory. Our base-case scenario assumes 500MW per year of new installations over this period, or a total increase of 2,500MW by 2014.

For offshore wind, we think the current FIT is high enough to give the required rate of return for the initial projects at least (i.e. those not too far offshore), but that there are other obstacles to the development of this technology, as explained in detail in our report *Which Way Blows the Wind?* (15 July 2009, see pages 19-22).

In summary, we see the main challenges as being:

- (i) Offshore wind is a new technology, and the pioneer plants reflect this fact. Baltic 1 and Alpha Ventus – the only two offshore-wind farms already operating – are small scale at 53MW and 60MW respectively;
- (ii) Much of the planned capacity already approved is of a much bigger scale than these two pioneer projects (i.e. >200MW) and is further out to sea in deeper water, thereby increasing the engineering and logistical challenges;
- (iii) The planned development of so much new capacity in such a relatively short space of time could create supply bottlenecks for turbines and for the ships needed to install them;
- (iv) Grid connections, particularly further out to sea, are a further potential bottleneck.

Accordingly, we concluded in our report *Which Way Blows the Wind?* that of the 6GW of offshore-wind projects already approved for development, only 2GW would be on the grid by 2013-14.

Our view on this has not changed since last year, and we therefore think that the Government's indicative trajectory for offshore wind out to 2014 is achievable. As a result, our base-case scenario assumes the same profile for the development of offshore capacity over 2010-14.

Conclusion: we assume 27.1GW of additional renewable capacity by 2014

Figure 42 sets out the profile for additions to renewable capacity that we assume in our base-case scenario based on the reasoning we have outlined above for solar and wind, and after concluding that the Government's indicative trajectory for new bio-mass and geo-thermal capacity looks reasonable.

In total, we project 27.1GW of additional capacity by 2014.

Figure 42: DB base-case assumed annual increase in renewable capacity over 2010-14 (MW)

	2010	2011	2012	2013	2014	TOTAL
Hydro	0	0	0	0	0	0
Onshore wind	+500	+500	+500	+500	+500	+2,500
Offshore wind	+135	+282	+360	+510	+738	+2,025
Bio-mass	+363	+308	+314	+280	+261	+1,526
Solar	+5,984	+4,500	+3,500	+3,500	+3,500	+20,984
Geo-thermal	3	7	10	13	17	50
TOTAL	6,985	+5,597	+4,684	+4,803	+5,016	+27,085

Source: German Government, Deutsche Bank

So, what is the overall picture when we sum together the net changes in fossil-fuel capacity and the additions to the installed base of renewables that we are projecting by 2014?

We see a total addition to gross capacity of 22GW by 2014

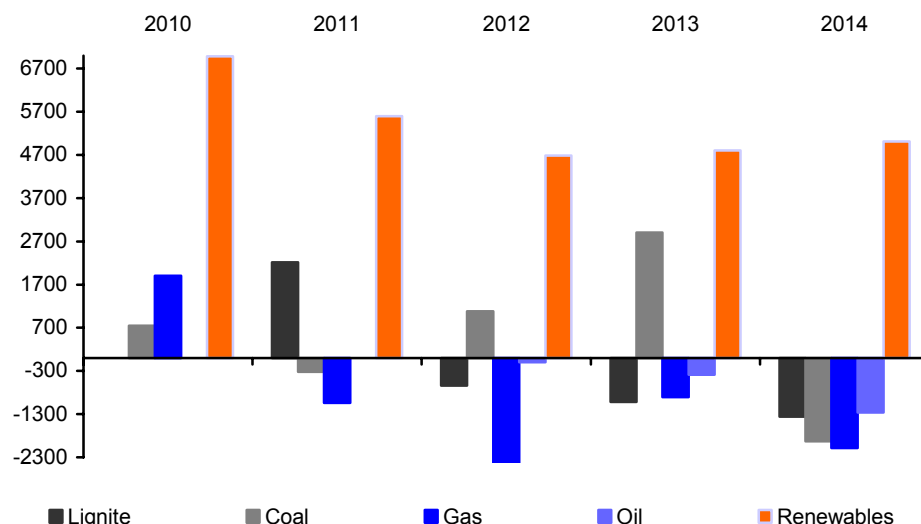
Taking all of the assumptions we have made above, Figure 43 shows the net result of all our calculations. In total, we expect 22GW of net additions to gross capacity by 2014.

Figure 43: DB base-case annual net change in gross generation capacity over 2010-14 by source (MW)

	2010	2011	2012	2013	2014	TOTAL
Lignite	0	+2,220	-642	-1,018	-1,355	-795
Coal	+750	-322	+1,885	+2,104	-1,926	+2,491
Gas	+1,906	+1,038	-3,357	-909	-2,088	-5,486
Oil	0	0	-94	-386	-1,264	-1,744
Renewables	+6,985	+5,597	+4,684	+4,803	+5,016	+27,085
TOTAL	+9,641	+6,457	+2,476	+4,594	-1,617	+21,551

Source: Deutsche Bank from Platts

Figure 44 shows closures and additions by fuel type over the period, and Figure 45 the change in the overall profile of the capacity mix over out to 2014.

Figure 44: DB base-case scenario for net change to gross capacity over 2010-14 (MW)

Source: Deutsche Bank

Figure 45: Estimated installed net capacity at the end of December (MW)

Capacity (end Dec)	2008	2009	2010	2011	2012	2013	2014
Hydro	4,200	4,200	4,200	4,200	4,200	4,200	4,200
Pumped storage	6,200	6,200	6,200	6,200	6,200	6,200	6,200
Nuclear	20,452	20,452	20,452	20,452	20,452	20,452	20,452
Lignite	20,803	20,803	20,803	23,023	22,381	21,363	20,008
Coal	28,245	28,245	28,995	28,673	30,558	32,662	30,737
Oil	6,167	6,167	6,167	6,167	6,073	5,687	4,422
Other gas	12,767	12,467	12,467	12,363	12,045	11,796	10,738
CCGT	14,756	14,756	16,662	15,729	12,691	12,031	11,000
Onshore wind	23,897	25,762	26,262	26,762	27,262	27,762	28,262
Offshore wind	0	15	150	432	792	1,302	2,040
Biomass	3,973	4,429	4,792	5,100	5,414	5,694	5,955
Waste	1,440	1,460	1,460	1,460	1,460	1,460	1,460
PV	5,877	8,877	14,861	19,361	22,861	26,361	29,861
Geothermal	7	7	10	17	27	40	57
Total	148,785	153,841	163,482	169,939	172,415	177,009	175,392

Source: Deutsche Bank

And putting all of our assumptions on both demand and supply over 2010-14 together, the final question in this section is what all of our assumptions mean for projected capacity margins by year-end 2014.

Conclusion: we see a de-rated capacity margin of 12% by 2014/15

Bringing together our assumptions for demand, new build, and closures, Figure 46 shows our base case for the de-rated capacity margin out to 2014. We project a large increase in total net capacity in the system (excluding embedded generation) over the period – from 139GW in 2009 to 160GW by 2014. With peak load in 2014 barely above the 2008 level (and still below the 2007 peak of 78.5GW), this would seem to indicate that the capacity surplus on the system is only set to get worse.

However, given that a large proportion of the new build is intermittent renewable generation, this headline capacity figure tells us little about how tight the system is. Little of the wind and none of the PV can be relied upon to meet peak system load.

While from 2009 to 2011 the net growth in reliable capacity exceeds the expected growth in demand, this starts to reverse from 2012 onwards. Our estimate of the de-rated capacity margin peaks at 25% in 2012 and then drops back to 21% for 2013, 20% for 2014. In 2014 we believe closures of reliable capacity will exceed new build and expect a tightening of the de-rated capacity margin to 12%.

Figure 46: DB-base case net capacity, load and de-rated capacity margin (winter, MW)

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Net capacity at peak	139,007	148,537	154,882	157,246	161,726	159,994
Not usable capacity	33,314	39,690	44,652	48,644	52,865	57,233
Maintenance and overhauls	3,614	3,862	4,027	4,088	4,205	4,160
Outages	4,170	4,456	4,646	4,717	4,852	4,800
System service reserves	5,893	5,937	5,982	6,027	6,072	6,118
Unavailable capacity	46,992	53,945	59,307	63,477	67,994	72,311
Reliably available capacity	92,015	94,592	95,575	93,769	93,731	87,683
Load	75,555	76,122	76,693	77,268	77,847	78,431
De-rated margin	22%	24%	25%	21%	20%	12%

Source: Deutsche Bank

The conclusion of our analysis is that while the current surplus of capacity may be maintained to 2013 given the stations already under construction, by the winter of 2014/15 we expect a level of tightness similar to that seen in 2006/07. At 12% the German system can still cover its expected peak load, but net exports at peak would mean there is little surplus.

The 2014 system should produce higher peaks than those seen this year and would be reaching a point where further capacity attrition could produce a more rapid upturn in peak prices and spreads. While surplus capacity looks likely to 2013, the capacity balance from 2014 onwards will depend on the strategic decisions of generators and the market framework.

This is a question we return to in our Conclusion to this report at the end of Section 3 below, once we have looked at the power prices and clean spreads generated by our model on the basis of the demand and capacity assumptions we have just set out above.

3. The outlook for power prices and spreads

In this section we look at the implications for power prices given our assumptions on demand and capacity changes out to 2014, comparing two trajectories for commodity prices.

First, we plug in our own assumptions on demand and changes in the capacity mix as set out in Section 2 above, and take the current forward curves for gas, coal, and oil as our commodity-price inputs. In this way we are able to impute what the forward baseload power curve is pricing in with regard to demand and capacity changes. Using these inputs, our model generates forward power prices and clean dark and spark spreads that are very close to the market values currently shown by forward power prices and spreads. This would suggest that the market is pricing in very similar assumptions to our own as far as the overall outcome on demand and capacity changes out to 2014 are concerned.

Second, we again take our own assumptions on capacity and demand but this time we use our own DB assumptions for the forward prices of gas, coal, and oil. We have lower gas prices over 2011-13 than those shown in current forward curves, but with gas prices recovering more rapidly thereafter than the market is assuming. By contrast we have higher coal and carbon prices relative to forward curves over 2011-12, but with coal prices falling back against the forward curve over 2013-14 as we assume that more global coal capacity (mining and exporting) comes onstream by those dates.

Using our own commodity-price inputs, we generate a slightly more positive projection for baseload prices over 2011-12 than that shown in the current forward baseload curve, with more positive clean spark spreads but more negative clean dark spreads than the market is currently projecting. After 2013, our baseload-price projections are essentially in line with those of the current forward curve.

The conclusion under our base-case scenario is that once fixed operating costs are taken into account beyond 2012 (i.e. after the move to full EUA auctioning), the outlook for the majority of Germany's coal and gas-fired generators is bleak. Coal generators will be running at an all-in loss over the entire 2011-14 period, and while gas generators do better than coal over 2011-12 given our low forecasts for market gas prices clean spark spreads drop sharply over 2013-14, with older gas plant then making all-in losses in excess of -€10/MWh generated, and even new CCGT plant failing to earn its cost of capital.

However, while the German power market undoubtedly looks to have material surplus capacity over 2011-13, an extra 4-5GW of closures above and beyond what we are pricing in under our base-case scenario would bring the de-rated capacity margin down below 10% by the winter of 2014-15, and to below 15% already by the winter of 2013-14. With these kinds of capacity margins, prices and spreads would be materially healthier by 2014/15 than our base case assumes. Accordingly, whether the margins for Germany's coal and gas-fired generators return to acceptable and sustainable levels from 2014-15 depends above all now on the decisions they make over the next four years on capacity closures and new build.

What is the forward power curve pricing in?

Figure 47 sets out the forward market values for the key commodities that drive power prices.

Figure 47: Commodity prices – current forward curves

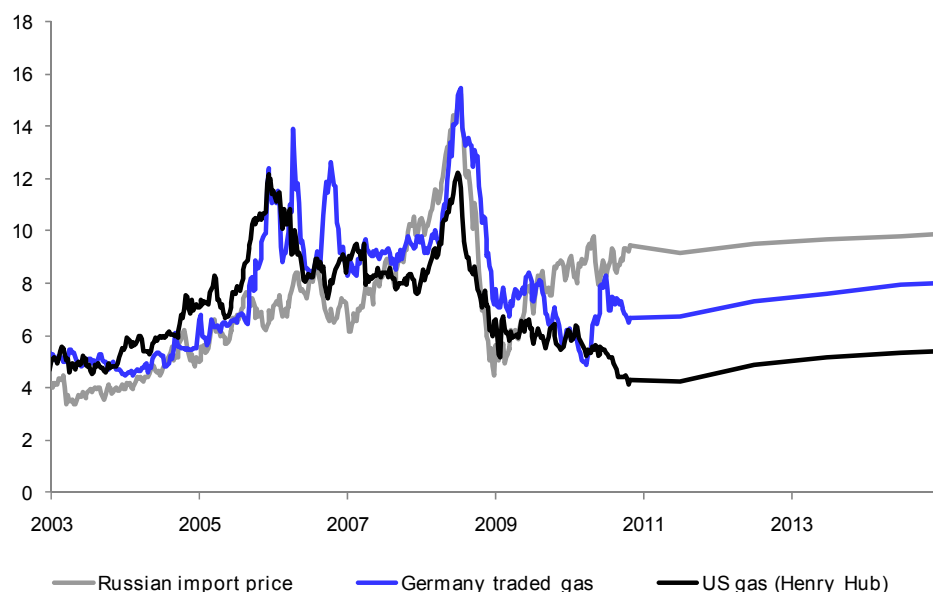
Prices	2008	2009	2010	2011	2012	2013	2014
\$/£	1.85	1.57	1.58	1.58	1.58	1.58	1.58
\$/€	1.47	1.39	1.36	1.36	1.36	1.36	1.36
€/£	1.26	1.13	1.16	1.16	1.16	1.16	1.16
Oil (Brent, \$/bbl)	97.4	73.3	84.3	81.9	85.0	86.7	88.0
Coal (ARA, \$/tonne)	139.7	83.5	103.2	98.8	106.0	111.4	113.6
CO ₂ (€/tonne)	22.9	13.4	14.7	15.7	16.0	16.4	16.7
US gas (Henry Hub, \$/MMBtu)	12.0	6.0	4.3	4.3	4.9	5.2	5.3
Russian import price (\$/MMBtu)	10.7	8.3	9.4	9.2	9.5	9.7	9.8
UK gas price (\$/MMBtu)	14.0	6.0	8.1	7.7	8.6	8.8	9.3
Germany gas (\$/MMBtu)	12.5	8.9	7.8	7.8	8.5	8.9	9.2
Germany gas (€/MWh)	29.0	21.8	19.7	19.7	21.4	22.3	23.2

Source: Reuters, Deutsche Bank

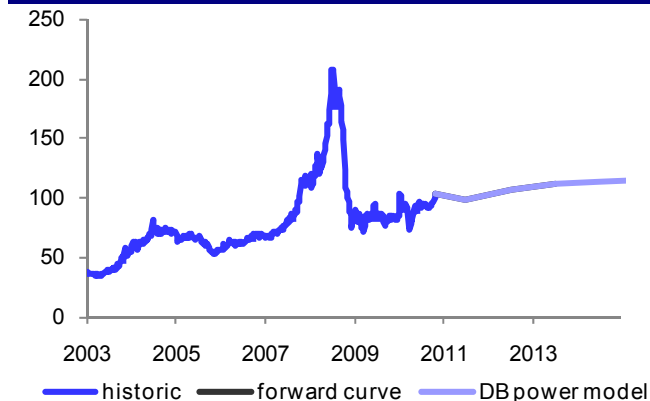
Putting these values into their recent historical context, Figures 48-50 then show the evolution of gas, coal and CO₂ prices respectively since 2003, together with the trajectory shown by the current forward curves over 2011-14.

Plugging these forward commodity prices into our model together with all of the assumptions we have made on demand and changes in the capacity mix as set out in Section 2 above, we derive the projection for German baseload power prices over 2011-14 shown in Figure 51.

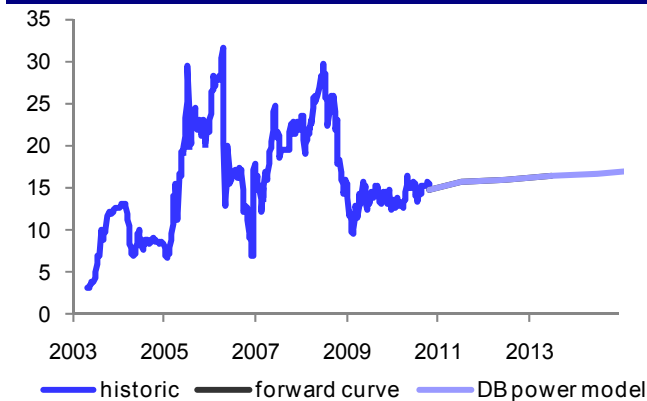
Figure 48: Historic and forward gas prices (US\$/MMBtu)



Source: Reuters, Deutsche Bank

Figure 49: Market forward curve for coal, as used in DB model under this scenario (ARA, \$/tonne)

Source: Reuters, Deutsche Bank

Figure 50: Market forward curve for carbon, as used in DB model under this scenario (€/tonne)

Source: Reuters, Deutsche Bank

As can be seen, using these inputs, our model is projecting a trajectory for future power prices that is almost exactly in line with the profile of the current forward curve.

Figure 51: German baseload power-price projections: current forward curve versus scenario using DB assumptions on demand, capacity changes, and current forward commodity prices (€/MWh)

Source: Deutsche Bank

Given that the projection shown in Figure 51 is generated by combining current forward prices for gas, coal and carbon and our own assumptions on demand and capacity changes over 2011-14, this would suggest that the market is assuming a very similar overall outcome on demand, nuclear extensions, and capacity changes to the one we have assumed in our base case and set out above in Section 2.

Figures 52 and 53 then show the outputs generated by our model for clean dark and spark spreads based on these inputs. For the analysis of clean spark spreads here, we have taken a new CCGT plant running at baseload levels with an efficiency rate of 58%.

Figure 52: Clean dark spreads using DB assumptions on demand and capacity changes and current forward commodity prices (36% efficiency, €/MWh)

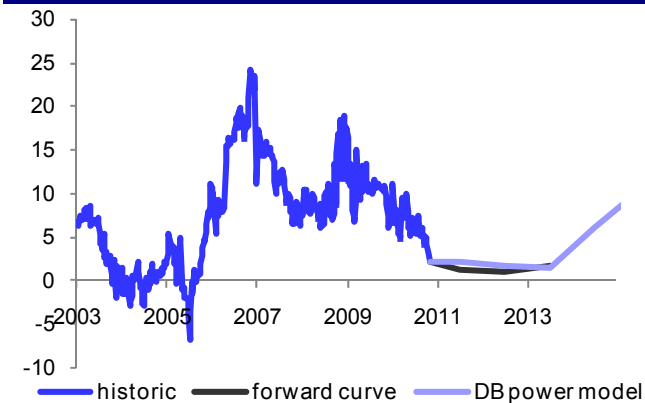
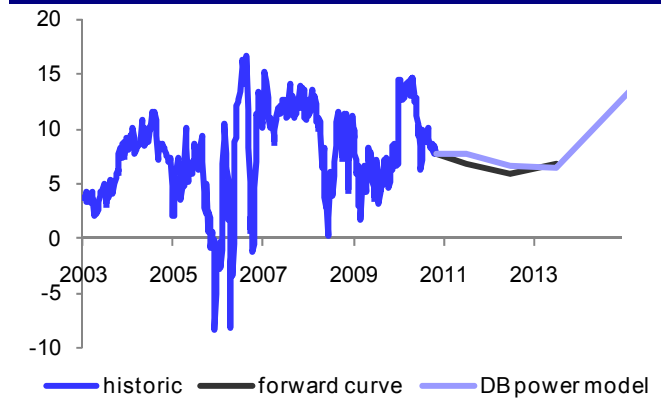


Figure 53: Clean spark spreads using DB assumptions on demand and capacity changes and current forward commodity prices (CCGT with 58% efficiency, €/MWh)



The clean dark spreads remain at just above cash costs over 2011-13, although start to recover from 2014. This is mainly because our model has the market beginning to tighten from 2014 in line with the lower de-rated capacity margin by that time generated by our assumptions on capacity changes over 2011-14.

The clean spark spreads trend lower over 2011-13 as the forward curve is currently projecting a recovery in market prices for gas over this period, but then, as with the dark spreads, start to recover somewhat over 2013-14 in line with a de-rated capacity margin that is beginning to tighten.

In short, the outlook for coal generators under these assumptions is for margins to remain at levels that barely cover cash costs for the next two years, followed by a recovery in clean dark spreads to around €6/MWh by 2014. For new CCGT plant, the prospects are better, as under this scenario clean spark spreads average €7/MWh over 2011-13, rising to €10/MWh by 2014.

However, there are also fixed operating costs to think about.

As shown in Section 1 above, the fixed costs for coal generators based on the actual load factor in 2009 would equate to €10/MWh generated. As a result, adjusting the clean spread shown in Figure 52 to include fixed costs, coal generators would be making an all-in real loss of about -€7/MWh in 2013 under this scenario for commodity prices, very close to the number we calculated under our earlier stylized analysis of the impact of full EUA auctioning (see Figure 20 in Section 1 above).

With regard to the all-in costs of a new CCGT generator with the profile shown in Figure 53, we estimate that the fixed costs are half those of an old OCGT plant (€20/kW and €40/kW respectively). Assuming a load factor of 80% for a new CCGT plant, the fixed cost would equate to about €3/MWh generated, so such plant would manage to cover both variable and fixed costs over 2011-13 on this basis although with an all-in spread of only about €3/MWh. However, an all-in return of only €3/MWh would not give new CCGT plant the return on investment their construction was premised upon, highlighting again the over-supply of capacity that on our projections the German system faces until 2014/15.

As far as older OCGT plant is concerned, the outlook depends more on peakload prices than baseload ones, and the trajectory for peakload prices generated by our model under this scenario is shown in Figure 54 below.

Clean spreads for older gas plant are much more negative than for new CCGT build until 2014, and assuming fixed costs of €10/MWh generated such plant would be making an all-in loss of -€14/MWh in 2013, almost exactly in line with the -€15/MWh we calculated under our stylized analysis of the impact of full EUA auctioning (see Figure 20 in Section 1 above).

Finally, for both CCGT and OCGT plant, we would again emphasize that we are here using market-gas prices to calculate spreads and all-in costs, rather than oil-indexed prices, and that if we were to use the oil-indexed price instead then even new CCGT plant would be running at or close to an all-in loss over 2011-12 under this scenario.

Figure 54 summarizes the projections for power prices and spreads out to 2014 using our own assumptions on demand and capacity changes but the current forward curves for commodity prices.

Figure 54: Projections for power prices and spreads over 2010-14 using DB demand and capacity assumptions and forward commodity prices (€/MWh)

Prices	2008	2009	2010	2011	2012	2013	2014
Baseload power price	69.7	41.5	49.5	47.8	49.8	51.5	57.2
Peakload power price	90.5	55.3	64.6	61.3	64.3	66.5	86.0
Clean dark spread	9.8	2.9	3.5	2.1	1.7	1.5	6.2
Clean spark spread, CCGT plant*	11.2	-1.5	9.7	7.6	6.6	6.5	10.6
Clean spark spread, OCGT plant**	-1.2	-12.2	2.2	-1.6	-3.4	-4.1	12.8

Source: Deutsche Bank; * Assumes a 58% efficiency rate and baseload prices; ** assumes 37% efficiency rate and peakload prices

In short, taking our own assumptions on demand and capacity changes over 2011-14 together with current forward commodity prices, our model projects very low spreads for coal and gas-fired generators over 2011-13, with a modest pick-up in 2014.

Once fixed operating costs are taken into account, we conclude that most coal and older gas-fired generators would be running at a loss on these assumptions, although new CCGT generators would be able to cover both variable and fixed costs assuming they could source their gas at market rather than oil-indexed prices. However, even new CCGT plant would not be earning its required return on capital over our forecast period, even assuming market rather than oil-indexed prices.

DB base-case projections for power prices and spreads

Figure 55 sets out the forward values for the key commodities that drive power prices using the base-case assumptions of the DB commodities-research team.

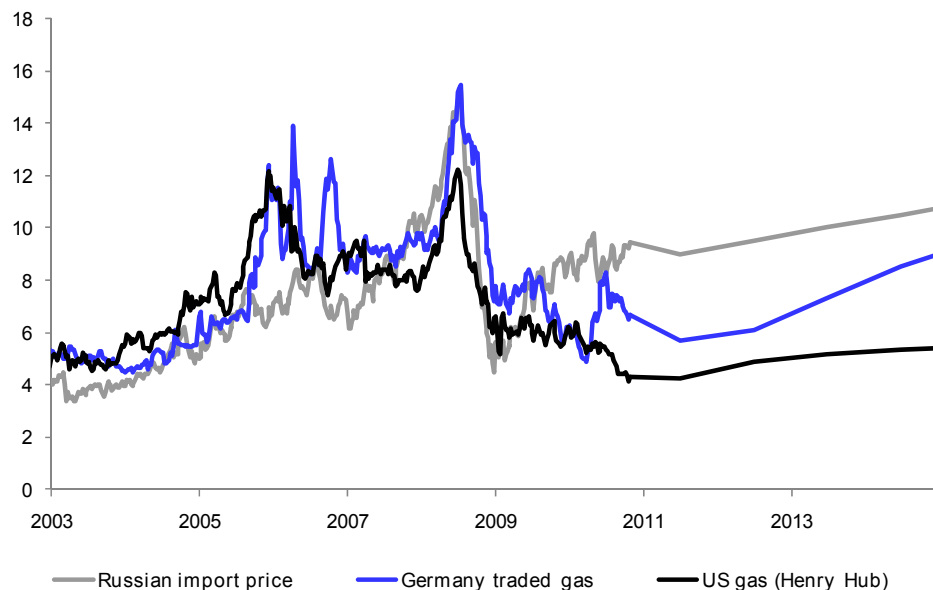
Figure 55: DB base-case commodity assumptions

Prices	2008	2009	2010	2011	2012	2013	2014
\$/£	1.85	1.57	1.58	1.58	1.58	1.58	1.58
\$/€	1.47	1.39	1.36	1.36	1.36	1.36	1.36
€/£	1.26	1.13	1.16	1.16	1.16	1.16	1.16
Oil (Brent, \$/bbl)	97.4	73.3	78.4	80.0	85.0	90.0	95.0
Coal (ARA, \$/tonne)	139.7	83.5	98.0	110.0	120.0	100.0	90.0
CO ₂ (€/tonne)	22.9	13.4	15.0	18.0	21.0	22.0	23.0
US gas (Henry Hub, \$/MMBtu)	12.0	6.0	4.3	4.3	4.9	5.2	5.3
Russian import price (\$/MMBtu)	10.7	8.3	8.8	9.0	9.5	10.0	10.5
UK gas price (\$/MMBtu)	14.0	6.0	7.6	6.7	7.1	8.5	10.0
Germany gas (\$/MMBtu)	12.5	8.9	7.4	6.7	7.1	8.5	10.0
Germany gas (€/MWh)	29.0	21.8	18.5	16.7	17.9	21.4	25.1

Source: Deutsche Bank

Putting these values into their recent historical context once again, Figures 56-59 then show the evolution of gas, coal and CO₂ prices respectively since 2003, together with the trajectory shown by DB's base-case projections as set out in Figure 54 above.

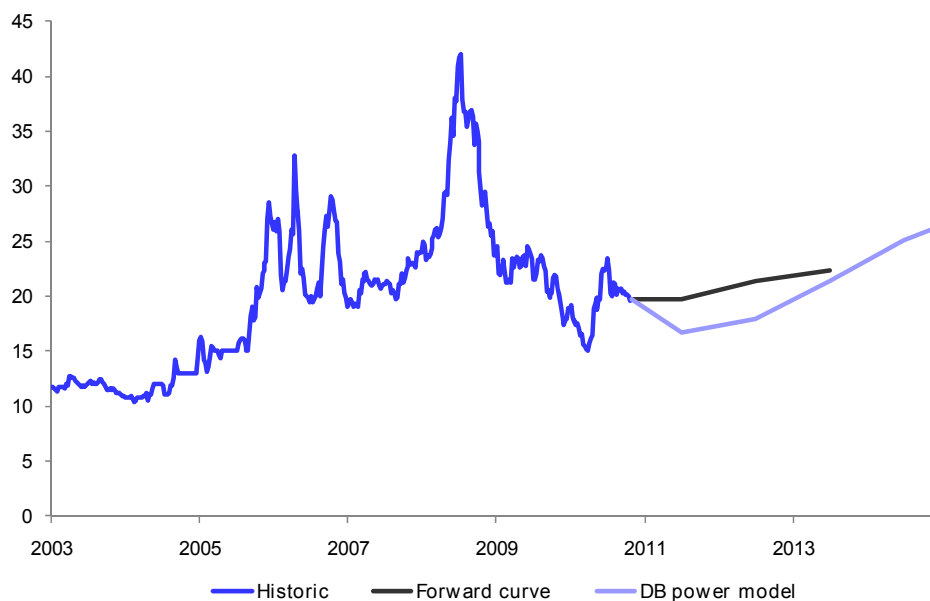
Figure 56: DB base-case projections for forward gas prices (US\$/MMBtu)



Source: Deutsche Bank

Our projections for gas prices are lower than those of the current forward curve over 2011-13 but move above forward prices from 2014 as we see them moving back towards convergence with oil-indexed prices by this time (see the report published by DB's oil-and-gas equity research team on 13 September 2010, *Battleground Analysis*, for more details on our rationale for expecting the disconnect between market and oil-and-gas prices to persist over 2011-13 but for the link with oil to start to re-assert itself by 2014-15).

Figure 57: DB base-case projections for traded German gas price (€/MWh)



Source: Deutsche Bank

For coal prices, we see continuing strong demand out of Asia (particularly China) keeping prices above the forward curve over 2011-12, but from 2013 onwards we expect to see capacity increases reflected in prices, which then come off over 2013-14 to levels below the forward curve.

Our CO₂-price projections are also above the forward curve, reflecting our view that despite the over-supply of EUAs over Phase 2 of the ETS there will still be a need for abatement to meet the Phase-3 cap and that generators will have to start hedging 2013 power sales over the next 12-24 months.

Figure 58: DB base-case projection for the coal forward curve (ARA, \$/tonne)

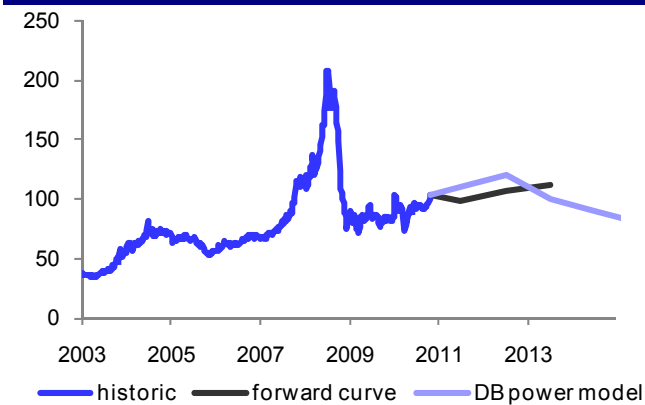
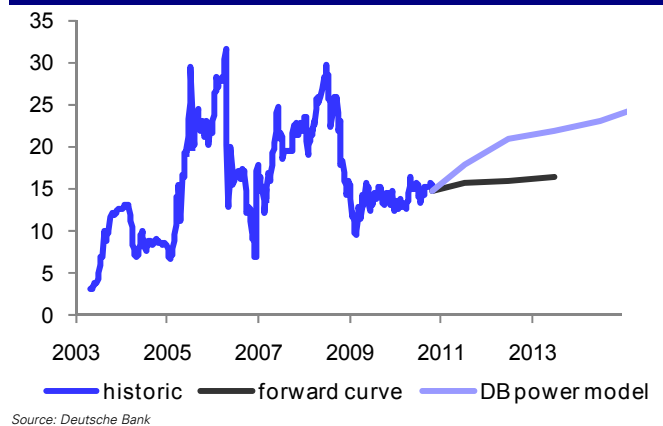
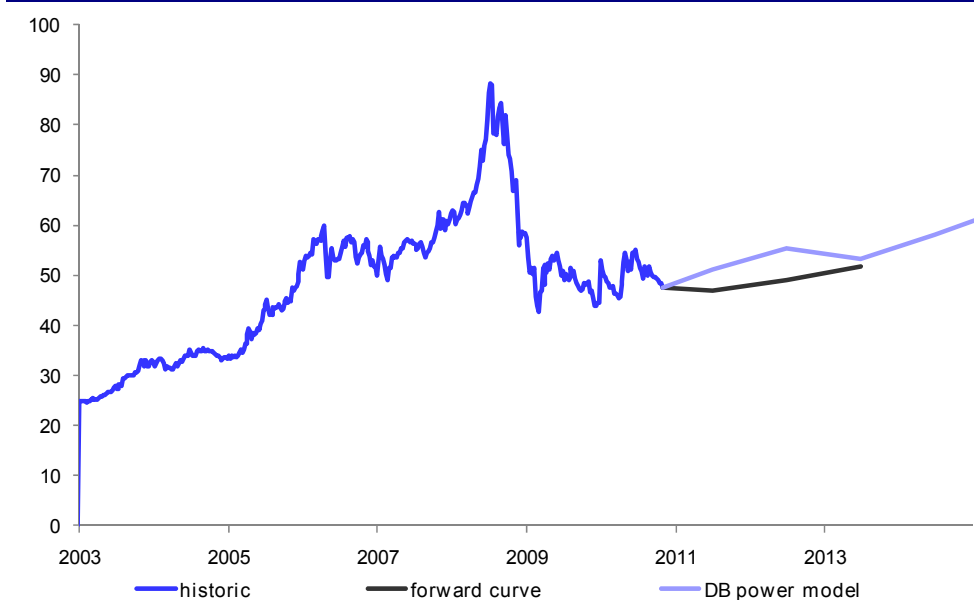


Figure 59: DB base-case projection for the CO₂ forward curve (£/tonne)



Plugging DB's base-case projections for forward commodity prices into our model while again taking our assumptions on demand and capacity changes, we derive our base-case projection for German baseload power prices over 2011-14, as shown in Figure 60.

Figure 60: DB base-case projection for German baseload power prices (£/MWh)



We project slightly higher prices than the current forward baseload curve over 2011-12, but from 2013 our forecasts are more or less in line with the market's projections.

The divergence between our projections and the current forward curve over 2011-12 mainly reflects our higher forecasts for coal and CO₂ prices over this period.

Figures 61 and 62 then show the outputs generated by our model for clean dark and spark spreads based on these inputs.

Figure 61: DB base-case projection for clean dark spreads (36% efficiency, €/MWh)

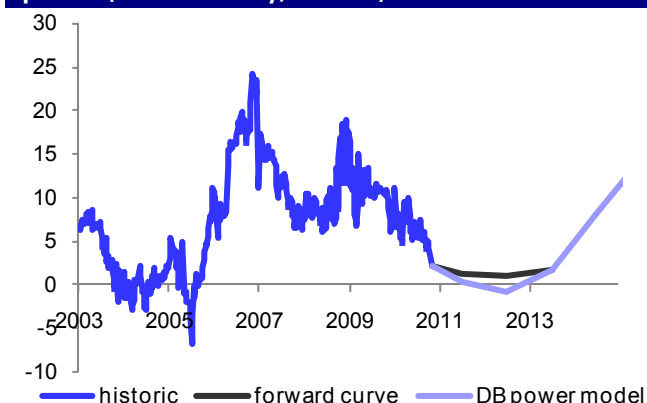
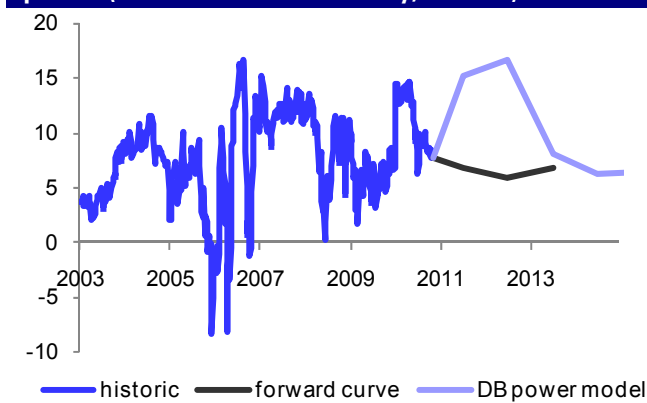


Figure 62: DB base-case projection for clean spark spreads (CCGT with 58% efficiency, €/MWh)



Given our projections for coal prices relative to the forward curve over 2011-12, dark spreads under our base-case scenario are actually negative over 2011-12, coming back into positive territory in 2013 once coal prices start to fall.

By contrast, the pattern in spark spreads is precisely the opposite: much healthier margins for CCGT operators over 2011-12 in line with our projections for market-gas prices, but then a sharp decline from 2014 onwards given our expectation that gas prices will trend back to oil-price convergence by 2015.

Adjusting our base-case clean dark spreads shown in Figure 61 to include fixed costs, we project that coal generators will be making an all-in negative spread of about -€11/MWh over 2011-12. Even though we project healthier clean dark spreads by 2014 of about €8/MWh, coal generators will still be making a loss of about -€2/MWh under our base-case scenario when our estimates of fixed costs per MWh generated are factored in.

With regard to the all-in costs for a new CCGT plant, with spreads at €15-16/MWh over 2011-12 and fixed costs of only about €3/MWh generated, our base-case scenario projects that such plant will actually be making a positive all-in return of about €12-13/MWh over the next two years. However, with spark spreads then dropping sharply from 2013, we see even the most efficient new gas plant in Germany will be covering cash costs but failing to make a return on capital from 2014.

Clean spreads for older OCGT gas plant using the peakload prices generated by our base-case scenario average €8-9/MWh over 2011-12, so assuming fixed costs of €10/MWh such plant would be making a low negative all-in spread of -€1/MWh (although with free EUAs over 2011-12 it would be making a small positive all-in real spread over these two years of €3-4/MWh).

With the disappearance of free EUAs from 2013, however, OCGT plant would be making an all-in loss of -€13/MWh in 2013, again very much in line with our earlier stylized analysis of the impact of full EUA auctioning (see Figure 20 in Section 1 above).

And again, we emphasize that we are here using market-gas prices to calculate spreads and all-in costs, rather than the oil-indexed gas price, which flatters all of these numbers for gas generators.

Figure 63 summarizes our base-case projections for German power prices and spreads out to 2014.

Figure 63: DB base-case scenario for power prices and spreads over 2010-14 (€/MWh)

Prices	2008	2009	2010	2011	2012	2013	2014
Baseload power price	69.7	41.5	48.4	51.1	55.4	53.3	58.0
Peakload power price	90.5	55.3	63.0	64.4	69.8	67.6	87.6
Clean dark spread	9.8	2.9	3.5	0.2	-0.9	1.6	8.2
Clean spark spread, CCGT plant*	11.2	-1.5	10.5	15.3	16.6	8.1	6.2
Clean spark spread, OCGT plant**	-1.2	-12.2	3.7	8.2	9.0	-3.1	6.3

Source: Deutsche Bank; * Assumes a 58% efficiency rate and baseload prices; ** assumes 37% efficiency rate and peakload prices

In short, taking our own assumptions on demand and capacity changes over 2011-14 together with our own DB projections for commodity prices, our model projects a bleak outlook over our forecast period for both coal and gas-fired generators.

Once fixed operating costs are taken into account, our base-case scenario projects that coal generators will be running at an all-in loss over the entire 2011-14 period.

Gas generators do better than coal over 2011-12 given our low forecasts for market gas prices and are able to cover their fixed costs over the next two years (OCGT plant helped here by its free Phase-2 EUA allowances).

However, with our base-case DB forecasts for a recovery in gas prices from 2013, clean spark spreads drop sharply over 2013-14, with older gas plant then making an all-in loss of -€13/MWh, and CCGT plant failing to earn its cost of capital.

Conclusion: capacity closures of >20GW needed to restore margins by 2014-15

Our analysis throughout this report leads us to conclude that the outlook for Germany's incumbent hard-coal and gas-fired generators over 2011-14 is bleak. With capacity margins currently very comfortable and the outlook for demand still muted, the forward curves for baseload power out to 2014 are well below new-entrant levels, and with clean spreads at three-year-lows and the prospect of full EUA auctioning from 2013, we think that many older, less efficient coal and gas plants will not be able to cover their fixed operating costs beyond 2012.

Moreover, although the forward baseload curve currently indicates that prices will remain well below fossil-fuel new-entrant levels for the foreseeable future, a material amount of new capacity will nonetheless come onstream by that date because (i) there is already 13.2GW of fossil-fuel capacity under construction, and (ii) the generous subsidies for renewables mean that wind, solar, and bio-mass capacity will carry on rising aggressively over the next few years irrespective of what happens to wholesale prices.

Worse still for incumbent fossil-fuel generators, most of this new renewable capacity will produce zero-marginal cost electricity once it is built, and will therefore displace fossil-fuel output in the merit order. This means that fossil-fuel plants in general – and incumbent coal and gas-fired generators in particular – will likely be running fewer hours with each year that passes while also receiving lower average baseload prices in the hours that they do run owing to the impact more low or zero-cost output will have on the price-duration curve.

Against this background we think that the move to full EUA auctioning from 2013 will force the owners of coal and gas-fired plant to think about shutting down more of their old capacity than they ordinarily would do based purely on standard operating lives, and the key here will be the responses of two major sets of players in the German power market: (i) the major generators/integrated utilities, and (ii) the 'long tail' in the German generation system.

If the major generators (the integrated utilities) are unwilling to cross-subsidize peaking stations from the cashflows of their lignite and nuclear output then a more rapid attrition of capacity can be expected from 2013 than we have assumed in our base-case scenario.

Just as important to the overall balance of the system, however, could be the behavior of the 'long tail' in the German generation system, i.e. the smaller units operated by regional companies, the combined heat and power capacity of the industrial users, and the co-gen stations of the district heating operators.

If these operators cross-subsidize generation from their other revenues then over-capacity may be a long-term systemic problem. However, if they prove less able to absorb lost generation revenues than the integrated utilities, then the tail could dwindle rapidly, and capacity margins reach tighter levels more quickly than our base-case scenario assumes.

Overall, the conclusion from our modeling is that while the 17.6GW of fossil-fuel closures we have assumed in our base-case scenario – or 5.5GW of net fossil-fuel closures after adjusting for assumed new build -- will not be enough to enable much of Germany's coal and gas-fired capacity to cover its fixed costs over 2013-14, an extra 4-5GW of closures on top would likely be enough for the remaining coal and gas plant to return to sustainable margins by the end of our forecast period.

This reflects our earlier analysis in Section 2, whereby even under our base-case assumption of 17.6GW of fossil-fuel closures we already expect a level of tightness by the winter of 2014/15 similar to that seen in 2006/07 (see Figure 46 in Section 2 above). With our base-case scenario projecting a de-rated capacity margin by the winter of 2014/15 of only 12%, the German generation system will still be able to cover its expected peak load at that time, but net exports at peak will leave little surplus.

As a result, while the German power market undoubtedly looks to have material surplus capacity over 2011-13, an extra 4-5GW of closures above and beyond what we are pricing in under our base-case scenario would bring the de-rated capacity margin down below 10% by the winter of 2014-15, and to below 15% already by the winter of 2013-14. With these kinds of capacity margins, prices and spreads would be materially healthier by 2014/15 than our base case assumes.

And given that our analysis above has shown that the market itself seems currently to be pricing in a similar overall outcome on demand and capacity changes over 2011-14 to that of our own base-case scenario, we conclude that the market would also welcome indications from generators of an accelerated closure programme over the next four years in the order of 21-23GW (always assuming no further new build beyond the 12GW we expect by the end of 2014).

In short, whether the margins for Germany's coal and gas-fired generators return to acceptable and sustainable levels from 2014-15 is to a large extent in their own hands, depending as it does above all now on the strategic decisions they make on capacity closures and new build.

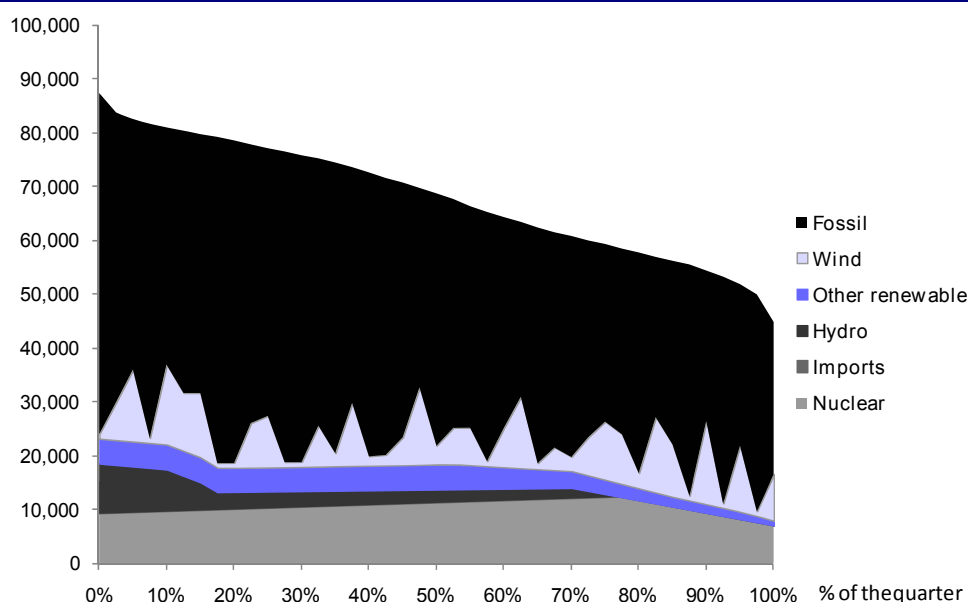
Power-price valuation

The theory behind our valuation

Our power-price analysis is based on a bottom-up, plant-by-plant model of the German power system. For each quarter of the year we construct a load-duration curve, estimate the output of non-thermal generation, and then model the price-setting thermal generation.

For illustrative purposes, Figure 64 shows the estimated load duration curve for Q1 2012. We use the actual load duration curve for 2007 as a base for future years (we do not use 2008 or 2009 since the shape of demand over the year was heavily affected by the impact of the recession and drop in industrial production). Our non-thermal generation profiles take into account wind intermittency, variable load from solar PV, and the effects of pumped-storage plant.

Figure 64: DB base-case load-duration curve and generation, Q1 2012(MW)



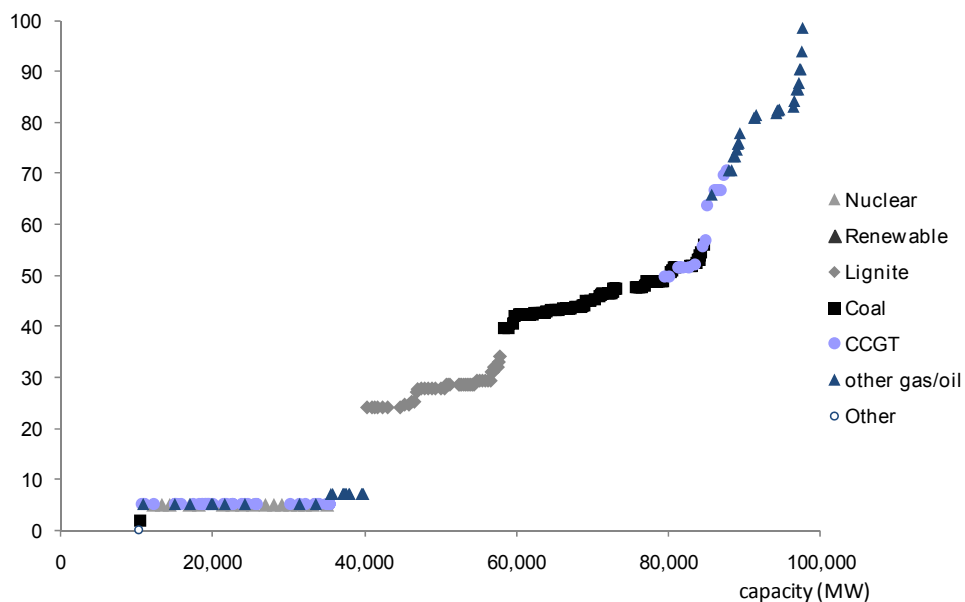
For the purpose of this model, we are focusing on the German system, rather than the wider, interconnected European electricity system. However, we do take into account the effects of imports and exports on the load to be met by German capacity.

We start with the actual imports and exports for 2008 and 2009 for each quarter, ranging from peak to off-peak times during the quarter. Germany has recently been a net exporter at peak times and importer at off-peak times/ during the summer. We assume that Germany will slightly increase its net exports over time, taking into account expected increased demand from the Czech Republic and France.

Once non-thermal generation has been netted off total demand (including embedded load), the remaining demand is met by nuclear and fossil-fuel generation capacity. Co-gen facilities are an important part of the German system and we constrain these to be running rather than allowing them to be price-setting.

We model over 280 generating units on the system and estimate marginal costs for fossil stations based on assumed delivered fossil-fuel prices and thermal efficiencies for the generating units. Figure 65 shows our estimated merit order for the German system for Q1 2012 based on fuel costs shown in forward curves.

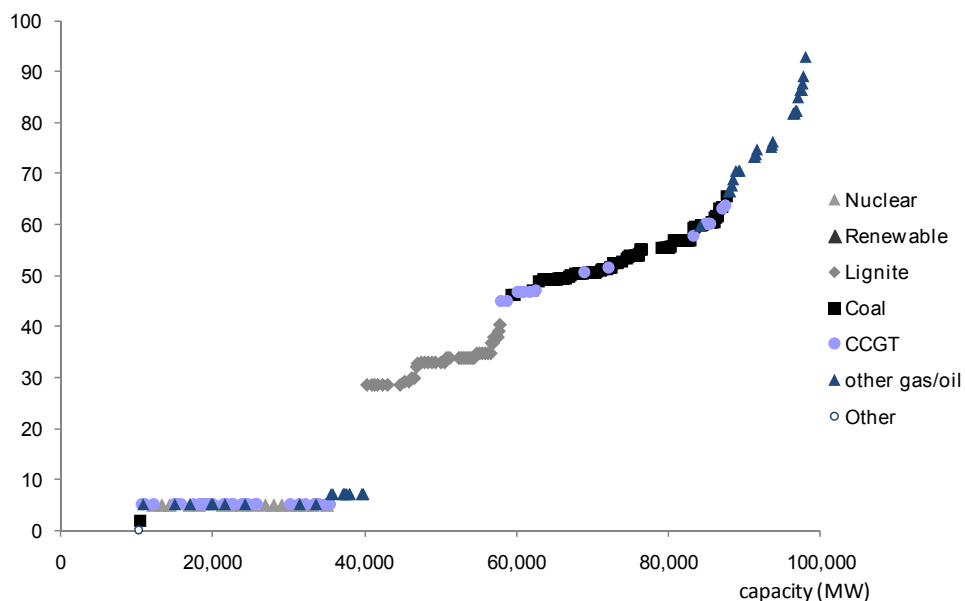
Figure 65: Q1 2012 merit order based on forward commodity prices (€/MWh)



Source: Deutsche Bank

Each unit is shown by a different marker. Lignite stations have lower marginal costs (including fuel and carbon) than hard-coal or gas stations. Open-cycle gas turbines and oil units are the most expensive plant on the system, setting prices at peak times.

Figure 66: Q1 2012 merit order based on DB base case (€/MWh)



Source: Deutsche Bank

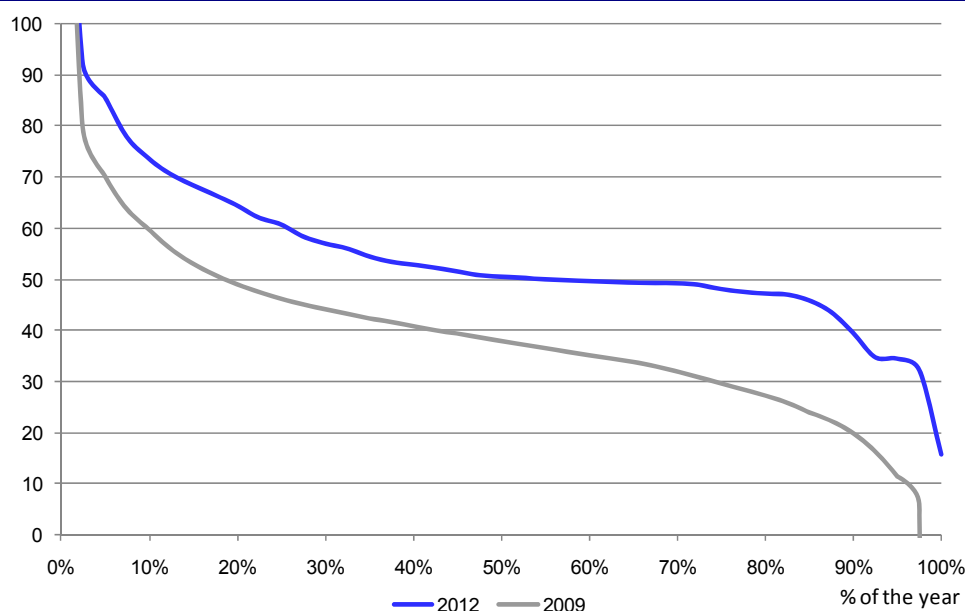
Figure 66 then shows the same merit order based on our own DB base-case assumptions for commodity prices for Q1 2012.

Carbon prices are higher, pushing up lignite costs in particular. Coal costs are higher, while gas prices are lower than the forward curve indicates. This causes newer, more efficient gas stations to run ahead of coal, though less efficient gas stations still only run at peak times.

Our modeling of the price-setting plant produces a price-duration curve for each quarter, showing the expected level of power prices at different times of the quarter, ranked from the hour of highest price to the hour of lowest price.

This price-duration curve includes adjustments we make for system constraints: at peak times (when prices rise above short-run marginal costs as the system is tight and additional capacity is needed to ramp up to meet demand); and at the periods of lowest demand (when plant may have to be paid to temporarily reduce generation, particularly if renewable output is high at times of low demand).

Figure 67: 2012 price-duration curve for DB base case, and 2009 actuals (€/MWh)



Source: EEX, Reuters, Deutsche Bank

Figure 67 shows the estimated price-duration curve for the whole year for 2012 in our base case. The figure shows that prices are above €100/MWh for a few percent of the year, above €50/MWh about 50% of the time, and dip sharply at off-peak times. This price-duration curve can be compared with the actual price-duration curve based on spot prices in the EEX for 2009. The main difference is the higher off-peak prices in 2012 partly coming from higher carbon and hard-coal prices in our DB base case.

Risks to our base-case valuation

There are both downside and upside risks to our modeling of German power prices.

On the downside, we would highlight the continuing fragility of the EU macro-economic recovery, and in particular the ongoing fiscal crises in a number of Eurozone Member States. This poses a broader risk to the economic health of the EU economy as a whole, and hence to the rate of future growth in German GDP and electricity demand. Other risks to the downside would be the possibility of a higher amount of new fossil-fuel build and/or fewer closures of older fossil-fuel plant over 2011-14 than we have assumed in our base-case scenario. Lower coal and/or gas prices than we are assuming would also lead to lower average power prices than those generated under our base-case scenario.

On the upside, the main risks would be the possibility that some or all of Germany's nuclear-power stations might not ultimately receive lifetime extensions as we have assumed, and that there will be less new fossil-fuel build and/or more closures of older fossil-fuel plant than we are forecasting. Higher coal and/or gas prices than we are assuming would also lead to higher average power prices than those generated under our base-case scenario. Higher demand from neighbouring markets than we have assumed would also be an upside risk to our base case.

Appendix A: Glossary

Figure 68 and 69 define the technical terms used throughout this report.

Figure 68: Glossary of terms

Abatement	In the carbon context, GHG-emissions reduction
All-in clean spreads	Clean spreads (see below) adjusted for the extra element of fixed costs per MWh generated
All-in real cash profit	The real cash profit earned by a fossil-fuel generator after adjusting the all-in clean spread for any free CO ₂ allowances allocated. Over Phase 2 of the EU-ETS German generators receive c.60% of their EUAs free of charge, but from the beginning of Phase 3, i.e. from 2013, they will have to pay for 100% of their allowances. This means that until the end of 2012 the all-in real cash profit a given fossil-fuel plant earns will be higher than the all-in clean spread, but that from 2013 the all-in real cash profit will be the same as the all-in clean spread.
Amended AEA	Germany's amended Atomic Energy Act, which entered into force in 2002
API2	This is the benchmark price reference for coal imported into northwest Europe
ARA	Amsterdam-Rotterdam-Antwerp, the reference import hub for EU coal
Bankability/banking/to bank	In the EU ETS context, the carrying over of carbon credits from one phase to the next
Baseload	The continuous minimum level of electricity demand
Baseload plant	A power plant that generates electricity to meet continuous minimum demand
BAU	Business as usual
bbl	Barrel
BDEW	<i>Der Bundesverband der Energie-und Wasserwirtschaft</i> , the German Energy and Water Association)
BMU	<i>Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit</i> , the Federal Environment Ministry of Germany
boe	Barrel-of-oil equivalent
Brent	Shorthand for the Brent crude-oil price, the key European reference price for oil
Bundesrat	The upper house of the German parliament
Bundestag	The lower house of the German parliament
c.	Circa
CAL	Calendar year, Cal-11 being for instance the contract for the delivery of a given commodity in the calendar year 2011
CDU	The Christian-Democratic Union, a political party in Germany
CCGT	Combined Cycle Gas Turbine
CCS	Carbon-capture and storage
CER	Certified Emissions Reduction
CHP plant	Combined heat-and-power plant
Clean dark spread	The margin earned by hard-coal generators net of their coal and CO ₂ input cost (i.e. the difference between the price at which they sell their output and these input costs)
Clean lignite spread	The margin earned by lignite power generators net of their lignite and CO ₂ input costs (i.e. the difference between the price at which they sell their output and these input costs)
Clean spark spread	The margin earned by gas-fired generators net of their gas and CO ₂ input costs (i.e. the difference between the price at which they sell their output and these input costs)
Clean spread	The margin earned by a fossil-fuel generator net of their fuel and CO ₂ input costs (see also clean brown spread/clean lignite spread, clean dark spread and clean spark spread)
CO₂	Carbon-dioxide
CSU	The Christian-Social Union, a political party in Germany
Co-generation/co-gen plant	A plant that produces both electricity and heat
DB	Deutsche Bank
€	Euro
€c	Euro cent
E	Estimated
EEX	European Energy Exchange
ENTSO-E	European Network of Transmission System Operators for electricity
EU	European Union

Source: Deutsche Bank, UNEP

Figure 69: Glossary of terms (continued)

EUA	European Union Allowance, the CO2 allowances used within the EU-ETS
EUR	Euros
EURACOAL	European Association for Coal and Lignite
ETS	Emissions Trading Scheme, often used as shorthand for the EU-ETS (see below)
EU-ETS	European Union Emissions Trading Scheme, also referred to simply as "the ETS" in this report
FDP	The free Democratic Party, a political party in Germany
FIT	Feed-in-tariff
FF plant	Fossil-fuel plant (i.e. a power plant fired either by lignite, coal, gas, or oil)
GDP	Gross Domestic Product
GHG(s)	Greenhouse gas(es)
GJ	Gigajoules
GW	Gigawatt, a measure of the capacity of a power station (one billion watts)
GWh	Gigawatt-hour, a measure of the output of a power station (one billion watts of power generated for an hour)
H1, H2	First half of the year, second half of the year
IPE	The International Petroleum Exchange
IPP	Independent Power Producer
IRR	Internal Rate of Return
kW	Kilo-Watt
LRMC	Long-Run Marginal Cost
M or m	Million
Merit order	The order in which power plants are despatched to generate electricity for distribution to the grid
Mt	Million tonnes or Mega-tonnes
MW	Megawatt, a measure of the capacity of a power station (one million watts)
MWh	Megawatt-hour, a measure of the output of a power station (one million watts of power generated for an hour)
Net capacity	Installed capacity adjusted for the power used by the station itself
NREAP	National Renewable Energy Action Plan
OCGT	Open Cycle Gas Turbine, an older form of gas-fired generation technology
P	Pence
p.a.	Per annum
p/y	Per year
Peakload	The maximum power requirement of a system at a given time
Phase 1, Phase 2, Phase 3	Trading periods of the EU ETS running from 2005 to 2007, 2008 to 2012, and 2013 to 2020 respectively
Phase 4	EU-ETS trading period, which will run over 2021-28
PV	Photovoltaic
Q1, Q2, Q3, Q4	First quarter, second quarter, third quarter, fourth quarter
Real cash profit	The underlying clean spread earned by a fossil-fuel generator after adjusting the clean spread for any free CO2 allowances allocated. Over Phase 2 of the EU-ETS German generators receive c.60% of their EUAs free of charge, but from the beginning of Phase 3, i.e. from 2013, they will have to pay for 100% of their allowances. This means that until the end of 2012 the real cash profit a given fossil-fuel generator earns will be higher than the clean spread, but that from 2013 the real cash profit will be the same as the clean spread.
SPD	The Social Democratic Party, a political party in Germany
SRMC	Short-Run Marginal Cost
t	Tonne
Therm	A unit of heat energy equivalent to 100,000 British thermal units
TWh	Terawatt-hour, a measure of the output of a power station (one million megawatts of power generated for an hour)
y/e	Year end
Zeebrugge gas price	The Zeebrugge hub is the natural-gas trading point in Belgium, and the price of gas at Zeebrugge is one of the key spot-market reference prices for the EU as a whole.
\$	US Dollar

Source: Deutsche Bank

Appendix 1

Important Disclosures

Additional information available upon request

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