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German Utilities

A new look at new entrants (revised)

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Power prices now look well supported in Germany at Euro 50/MWh. Following the European Commission's rejection of Germany's 4+14/4+10 rules we think gas is the new entrant of choice at Euro 50/MWh. We also think the only viable energy policy for Germany is to make clean coal competitive with gas via subsidies funded from windfall taxes on nuclear extensions. Assuming a long-term power-price of Euro 50/MWh (previously Euro 45/MWh), and that the planned nuclear phase-out will have to be revoked, our revised price target for E.ON (BUY) is Euro 118 (previously Euro 110) and for RWE Euro 94 (BUY) (Euro 77.5).

The rejection of Germany's 4+14rule makes gas the new entrant of choice. Without the subsidy implied by the 4+14/4+10 rules, we think gas is now the clear new entrant of choice against conventional coal and lignite plants, and that much of the 22GW of planned new plant in Germany by 2012 will not now get built. Given potential capacity needs on our estimates of 16GW by 2012 and 42GW by 2020, we therefore see strong support for power prices and, in time, for the case for extending the operating lives of Germany's nuclear power stations to 60 years.

Phasing out nuclear power is not a viable policy option, in our view. We estimate that if the planned phase-out of nuclear power goes ahead, a total of 42GW of new plant will be required by 2020: 20GW to replace lost nuclear plants, 12GW to meet organic-demand growth and ensure adequate reserve margins, and 10GW to replace old fossil-fuel plant. In addition, we estimate that CO2 emissions from power generators would rise to 293m tonnes from 250m tonnes over 2010-20, and that Germany would therefore find it impossible to meet its aspiration of a 40% cut in GHG emissions by 2020 against 1990 levels. Moreover, we calculate that gas used for power generation would increase to 503TWh from 140TWh over 2005-20 on this scenario, thus dramatically increasing Germany's dependence on foreign energy supplies.

Germany can lead the world in carbon capture and storage (CCS). We think Germany can only reduce CO2 emissions and bolster security of supply by extending its nuclear plants' operating lives and subsidising CCS plants with taxes on these extensions. We estimate that CCS is viable at Euro 64/MWh.

Valuation and risks

New entrants will receive all of their CO2 allowances for free over 2008-12, but as incumbents from 2013 could face full auctioning in subsequent ETS periods. Taking DB's medium-term oil-price forecast of \$44/boe, we estimate the price for new-entrant gas with free emissions for the first five years but thereafter paying for 100% of its allowances at Euro 50/MWh, and this is our new long-term price assumption (we would emphasise, however, that gas would require a price of Euro 54/MWh with carbon fully priced in at Euro 25/tonne). We also assume an extension of Germany's nuclear power plants to 60 years, and a 50% tax rate on all nuclear output going forward, with the proceeds used to make CCS competitive with gas. On the basis of these new assumptions, our revised price targets for E.ON and RWE are Euro 118/share and Euro 94/share respectively. The main risks to our valuations are lower carbon and gas prices than we are assuming.

Revision: Modest numerical amendments to Figures 45 and 46.

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DISCLOSURES AND ANALYST CERTIFICATIONS ARE LOCATED IN APPENDIX 1

Emerging Themes

Top picks		
E.ON (EONG.DE),EUR98.64		Buy
RWE (RWE.DE),EUR80.00		Buy

Companies featured			
E.ON (EONG.DE),EUR98.64			Buy
	2005A	2006E	2007E
DB EPS (EUR)	5.28	6.62	7.67
P/E (x)	13.9	14.9	12.9
EV/EBITA (x)	8.7	10.1	9.0
RWE (RWE.DE),EUR80.00			Buy
	2005A	2006E	2007E
DB EPS (EUR)	4.05	4.48	5.94
P/E (x)	12.7	17.8	13.5
EV/EBITA (x)	9.6	11.6	8.7

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Investment thesis

Outlook: Germany now needs a coherent energy policy

Germany's energy-policy framework contains unsustainable contradictions. Under current legislation 20GW of nuclear capacity will be phased out by 2022, thus undermining Germany's key objectives of reducing CO₂ emissions by 40% by 2020 against 1990 levels, and ensuring security of supply. This is because phasing out nuclear power would almost double the amount of new capacity likely to be required by 2020 once organic-demand growth and the withdrawal of old fossil-fuel plant is taken into account, most of which -- 28GW out of 42GW, in our view -- would have to be gas. On our calculations, this would mean that CO₂ emissions in 2020 from power generation would be similar to 2005 levels at nearly 300m tonnes, while gas used in power generation would increase by 362TWh over 2005-2020, a figure equivalent to one third of Germany's total gas consumption in 2005.

Nuclear extensions and support for clean coal are the answer

Following the European Commission's rejection of Germany's proposed 4+14/4+10 rules, we think that gas is the new-entrant fuel of choice against conventional coal and lignite plants. However, we also think that advances in clean-coal technology could make CCS coal and lignite plants competitive with gas in the relatively near future. And in our view the only way for Germany to achieve its policy objectives on carbon emissions and security of supply is to extend the lifetime of its nuclear plants and subsidise CCS plants with windfall taxes on these extensions.

On our calculations, extending the lifetime of all nuclear-power plants in Germany to 60 years could raise an extra Euro 800m per year initially for the Government (rising to Euro 2bn per year by 2022), money which could then be used to incentivise clean-coal plants to be built. In our view, the price of CCS (Euro 64/MWh on our estimates) needs to be compared with new-entrant gas with carbon fully priced in (Euro 54/MWh) because CCS has a long lead time and will therefore not be competing with gas over 2008-12, but rather from the start of the following ETS trading period. And by that time, we think it is rational to assume that new-entrant gas plants will have to pay for all their allowances. We calculate that setting aside the incremental taxes from nuclear extensions in competitive auctions for bidders looking to cover the price gap to new-entrant gas could encourage 1,100MW of new clean-coal capacity per year initially, but that this figure would rise quickly as the incremental tax take rose.

Valuation and risks

New entrants will receive all of their carbon for free over 2008E-12, but will be treated as incumbents from 2013 and on a worst-case basis could therefore face full auctioning from 2013E onwards. Taking DB's medium-term oil-price forecast of \$44/boe, we estimate the price for new-entrant gas with free carbon for the first five years but thereafter having to pay for 100% of its allowances at Euro 50/MWh. Accordingly, this is our new long-term price assumption for the German utilities. We also assume an extension of Germany's nuclear power plants to 60 years, and a 50% tax rate on all nuclear output going forward, with the proceeds used to make CCS competitive with gas. On the basis of our new assumptions, our revised price targets for E.ON and RWE are Euro 118/share and Euro 94/share respectively.

The main risks to our valuations are that gas and carbon prices are lower in future than we are now assuming, and/or that the European carbon-trading scheme breaks down in future, thereby making conventional coal the new entrant of choice and therefore reducing our long-term power-price forecast.

The structure of this report

This report is divided into four main sections.

1. Gas is now the clear new entrant of choice in Germany

Under Germany's plan to guarantee free carbon allowances to new entrants for 18 and 14 years in its Phase-1 and Phase-2 NAPs respectively, we estimate that new coal and lignite plants would both have received a subsidy amounting to about 25% of their capital costs.

Without the subsidy entailed by this rule, we calculate that gas is now the clear new entrant of choice against conventional coal and lignite plants. This is because at our assumed carbon price of Euro 25/tonne a new gas plant would earn its required rate of return with 100% auctioning of allowances at a power price of Euro 54/MWh, whereas coal would require a price of at least Euro 59/MWh, and lignite at least Euro 60/MWh.

The cancellation of the 4+14/4+10 rules means that Germany now has to find an alternative way of balancing the need to ensure security of supply against the objective of reducing future emissions.

2. Germany's current energy policy is untenable

Under current legislation, 20GW of nuclear capacity will be phased out in Germany by 2022, and if this actually happens we estimate that a total of 42GW of new plant will be required by 2020. This assumes 20GW to replace withdrawn nuclear plants, 12GW to meet organic demand growth while ensuring a reserve margin of 10%, and 10GW to replace old, inefficient fossil-fuel plant.

Under this scenario, we estimate that CO₂ emissions from the power-generation sector would increase by 16% between 2010 and 2020 (to 293m tonnes from 250m tonnes), and that Germany would therefore find it impossible to meet its policy aspiration of a 40% cut in GHG emissions by 2020 against 1990 levels. Moreover, gas used for power generation would increase by 260% over 2005-2020, to 503TWh from 140TWh, thus dramatically increasing Germany's dependence on foreign energy supplies.

So, far from reducing carbon emissions and securing future energy supplies, current policies would increase both emissions and Germany's dependence on foreign gas imports.

3. The solution is nuclear extensions and support for clean coal

We think the only way for Germany to achieve its dual policy objectives of reducing carbon emissions and ensuring security of supply is to extend the lifetime of existing nuclear plants and to subsidise new CCS plants with windfall taxes on these extensions.

On our calculations, extending the lifetime of all nuclear-power plants in Germany to 60 years could raise an extra Euro 800m per year initially for the Government (rising to Euro 2bn per year by 2022), money which could then be used to incentivise clean-coal plants to be built.

On the assumption that new-entrant gas with carbon fully price in requires a price of Euro 54/MWh and CCS plants a price of Euro 64/MWh, we calculate that setting aside the incremental taxes from nuclear extensions in competitive auctions for bidders keen to cover the price gap to new-entrant gas could encourage 1,400MW of clean-coal capacity per year by 2012, or a total of 7,500MW within the first six years of such a policy being implemented.

We calculate that the two great advantages of such a policy are: (i) it would enable Germany to reduce its CO₂ emissions from power generation by 50% against 1990 levels by 2020, and hence allow this sector once again to achieve more than its fair share of the overall reduction in emissions the Government is targeting by 2020 (a 40% cut against 1990 levels); (ii) it would limit the rise in Germany's gas imports over 2005-2020 to 92TWh compared with the 362TWh increase over this period that would otherwise happen.

4. Valuation implications

New entrants will receive all of their carbon for free over 2008-12, but will be treated as incumbents from 2013 and on a worst-case basis could therefore face full auctioning from 2013 onwards.

Taking DB's medium-term oil-price forecast of \$44/boe, we estimate the price for new-entrant gas with free carbon for the first five years but thereafter having to pay for 100% of its allowances at Euro 50/MWh. Accordingly, this is our new long-term price assumption for the German utilities.

We also assume an extension of Germany's nuclear power plants to 60 years, and a 50% tax rate on all nuclear output going forward, with the proceeds used to make CCS competitive with gas.

The main risks to our valuations are that gas and carbon prices are lower in future than we are now assuming, and/or that the European carbon-trading scheme breaks down in future, thereby making coal and conventional lignite new build the new entrant of choice and therefore reducing our long-term power-price forecast.

We conclude this report with separate sections on E.ON and RWE, briefly outlining the investment case for each on the basis of our new assumptions.

1. Gas is now the clear new-entrant of choice in Germany

Under Germany's plan to guarantee free carbon allowances to new entrants for 18 and 14 years in its Phase-1 and Phase-2 NAPs respectively, we estimate that new coal and lignite plants would both have received a subsidy amounting to about 25% of their capital costs.

Without the subsidy entailed by this rule, we calculate that gas is now the clear new entrant of choice against conventional coal and lignite plants. This is because at our assumed carbon price of Euro 25/tonne a new gas plant would earn its required rate of return with 100% auctioning of allowances at a power price of Euro 54/MWh, whereas coal would require a price of at least Euro 59/MWh, and lignite at least Euro 60/MWh.

The cancellation of the 4+14/4+10 rules means that Germany now has to find an alternative way of balancing the need to ensure security of supply against the objective of reducing future emissions.

The 4+14/4+10 rules in theory

In the Phase-2 NAP it originally submitted to the European Commission, Germany proposed awarding 14 years' worth of carbon allowances free of charge to new-entrant power plants commissioned over 2008-12, provided that the plants met certain criteria. The NAP envisaged two kinds of new entrants: (i) new installations, and (ii) replacement plants.

New installations; benchmarking against best available technology

The way the NAP envisaged this 4+10 rule working for new installations was that all new plants that met best-available technology (BAT) benchmarks would receive as many permits as they needed to run baseload over the first four years of their lifetime, and then for the next ten years they would receive the number of permits they needed to run for the same number of hours that they had *actually* run on average during their first four years.

In all essential respects the 4+10 rule was more or less identical to the so-called 4+14 rule that had been proposed by Germany in its Phase-1 NAP, and Figure 1 sets out the key technology benchmarks stipulated for new entrants in the Phase-2 NAP depending on whether they were gas or coal plants.

Figure 1: Criteria for allocation to new entrants under Germany's 4+10 proposal

Fuel	Efficiency benchmark (assumed carbon-intensity of fuel)	Number of hours assumed in first four years	Implied load factor	Number of free permits allocated per 1,000MW of new plant
Gas	0.365	7,500	85.6	2,737,500
Coal	0.75	7,500	85.6	5,625,000

Source: German Government

For new gas plants, the 4+10 rule assumed a carbon-intensity rate of 0.365, or, in other words, that new plant would emit 0.365 tonnes of CO₂ per MWh generated. It would be assumed that the plant would run for 7,500 hours per year, and hence that it would emit 2.7m tonnes of CO₂ annually for every 1,000MW of capacity at the assumed load factor.

For new coal plants, the allowed carbon-intensity rate was 0.75, meaning that it was assumed new coal plant would emit 5.625m tonnes of CO₂ annually for every 1,000MW of capacity.

As a result, the 4+10 rule envisaged awarding 2.7m and 5.6m carbon allowances per GW per year free of charge to new gas and coal plants respectively over the first four years of their operating lives. For the following ten years the new plant would then have received an annual allotment of allowances based on the average load factor at which it had actually run over the first four years, again free of charge.

Replacement plants: the 4+14/4+10 transfer rule

Given that Germany is rich in lignite deposits but that the carbon-intensity of lignite (or brown coal) is greater than that of hard coal, the rules for new installations described above (generous as they were) would probably not have been enough to incentivise new lignite plants to be built.

As a result, Germany's Phase-2 NAP (just like the Phase-1 NAP) made special provisions for new power plants that would replace old, less efficient plants. The rule here was that for the first four years of its operating life a replacement plant would receive the same number of allowances as had been awarded historically to the plant it was replacing, and that thereafter it would receive 100% of its needs capped at the BAT carbon-intensity level for hard coal.

So, a new lignite plant with a BAT carbon-intensity factor of 0.93 compared with the older plants it was replacing that might have had a carbon-intensity factor anywhere between 1.2-1.4 would receive more permits than it needed for the first four years of its life. The surplus permits it had left over could then be used over the remaining ten years of its life when it would receive fewer permits than it needed each year given that its BAT carbon-intensity factor of 0.93 would be above the 0.75 level stipulated for all coal plants – whether hard coal or brown coal – in the NAP.

Figure 2: BAT lignite plants compared against older lignite plants under Germany's Phase-2 NAP 4+10 rule

Fuel	Carbon-intensity factor	CO2 emissions per 1,000 MW running 7,500 hours per year	Implied allocation at 85% compliance factor	Implied annual surplus for first four years	Implied annual deficit for following 10 years
BAT lignite	0.93	6,975,000	n/a	1,312,500	1,350,000
Old lignite	1.3	9,750,000	8,287,500	n/a	n/a

Source: German Government

Figure 2 shows a stylised analysis of how this would work in the case of a new BAT 1,000MW lignite plant replacing an older 1,000MW plant with a carbon-intensity factor of 1.3. In Germany's Phase-2 NAP it was proposed that incumbent plants would receive 85% of their carbon requirements for free, so a 1,000MW lignite plant running baseload would receive 8.3m tonnes a year free of charge.

Given that a new BAT plant would emit only 6.975m tonnes per year running baseload, it would accumulate an annual surplus of 1.3m tonnes for the first four years of its life. This surplus could then be used to offset almost exactly over the following four years the annual deficit it would incur running baseload but capped in terms of its free allocation at the BAT carbon-intensity factor of 0.75.

In other words, a 1,000MW replacement lignite plant would effectively have received its entire carbon requirement for running baseload for free over the first eight years of its life under the 4+10 rule for replacement plants, while for the remaining six years of its first fourteen years it would have received 81% of its requirement for free (i.e. 5.625m tonnes versus the 6.975m tonnes it would need to run 7,500 hours a year).

In practice, Germany had already signalled to the Commission that it was prepared to cut its total allocations over Phase 2 – and hence reduce its compliance factor – so if these rules had been allowed to stand the economics in the final analysis would probably not have been quite as attractive as this. Nonetheless, an investor in a replacement lignite plant would still clearly

have had a strong incentive to build. Moreover, the benefit of this transfer rule for replacement plants was even more pronounced in the Phase-1 NAP, not just because the free allocation period was 4+14 years rather than 4+10 but also because the compliance factor for incumbent installations in Phase 1 was 97% rather than 85%.

So, any new BAT lignite plants commissioned to replace older installations in Phase 1 of the ETS would have received 97% of their requirement for free rather than 85%, so the surplus to be carried forward for the remaining fourteen years would have been all the greater.

Figure 3: BAT lignite plants compared against older lignite plants under Germany's Phase-1 NAP 4+14 rule

Fuel	Carbon-intensity factor	CO2 emissions per 1,000 MW running 7,500 hours per year	Implied allocation at 97% compliance factor	Implied annual surplus for first four years	Implied annual deficit for following 14 years
BAT lignite	0.93	6,975,000	n/a	2,482,500	1,350,000
Old lignite	1.3	9,750,000	9,475,500	n/a	n/a

Source: German Government

Under the 4+14 rule in Germany's Phase-1 NAP a 1,000MW replacement lignite plant would effectively have received its entire carbon requirement for running baseload for free over the first 11 years of its life, while for the remaining seven years of its first 18 years it would have received 81% of its requirement for free (i.e. 5.625m tonnes versus the 6.975m tonnes it would need to run 7,500 hours a year).

The fact that a number of replacement lignite plants are currently at various stages of planning in Germany (with one already under construction) proves that the 4+14 and 4+10 rules have been effective in incentivising investment in new lignite plants.

However, whether the investments in these lignite plants will now proceed as planned following the European Commission's rejection of the 4+10 and 4+14 rules in its ruling on Germany's Phase-2 NAP of 29 November 2006 remains to be seen. This is a question we treat at greater length in Section 2 below.

The 4+14 rule and security of supply

The motivation behind the 4+14 and 4+10 rules can be inferred from the fact that the rules did not give a single BAT benchmark for new build, but separate carbon-intensity factors according to whether the plant in question was gas fired or coal fired.

This effectively neutralized the cost of carbon to these different fossil fuels and therefore made coal competitive against gas as a new-entrant fuel. This was despite the fact that policymakers were fully aware that Germany's participation in the ETS and the Kyoto Protocol made it rational to assume that the cap on carbon emissions introduced in 2005 would tighten incrementally over time, such that it would likely be much tighter after the first 18 years of a new coal plant had passed.

As a result, it seems reasonable to assume that other policy objectives were in play here, and we would argue that the granting of a separate benchmark for coal, together with the transfer rules for replacement lignite plants, were designed to encourage new coal and lignite plants to be built lest Germany become too dependent on imported gas for its power-generation requirements over time.

In other words, the 4+14 and 4+10 rules were designed to ensure that the separate policy objective of securing Germany's energy supplies was taken into account in setting the policy for reducing Germany's carbon emissions over time. We also think it is reasonable to assume that in attempting to guarantee a future for new coal and lignite plants in this fashion

policymakers hoped that carbon and power prices would be lower than would be the case if all future new build were gas fired.

In our view, however, the 4+14 and 4+10 rules were misconceived, and we would highlight four main problems in particular. We now examine each of these problems in turn, using the 4+14 rule from the Phase-1 NAP to exemplify each point.

Problem 1: the 4+14 rule was a subsidy for coal and lignite

Before the introduction of the ETS in January 2005, building a new fossil-fuel fired power plant required the investor to take a view on the fuel and operating costs (fixed and variable) that would need to be covered over the lifetime of the project in order for the necessary return on capital invested to be earned.

Today, however, investors in new fossil-fuel fired power plants have to take a view on carbon costs as well, taking into account, in the process, the likelihood that carbon emissions will become a scarcer commodity over time as the cap is incrementally tightened in future.

With this in mind, we examine below the economics of building a new gas, coal, and lignite power plant making the following assumptions in each case:

1. that the expected operating life of the plant is 40 years.
2. that the cost of carbon over the lifetime of the plant is Euro 25/tonne (this corresponds to our price forecast for carbon over 2008-12 and we think a prudent investor would project a conservative view over the lifetime of the project on the assumption that the carbon cap will tighten incrementally over time), and that there is no free allocation of carbon. In other words, we are assuming that the new entrant in each case has to pay for 100% of its carbon requirements over the lifetime of the project. We make this assumption for both theoretical and practical reasons.
3. Theoretically, we believe this is the correct methodology to use in order to calculate the true economic cost of a new power plant in a carbon-constrained world, and hence the true size of the subsidy that new coal and lignite plants would have received.
4. Practically, we think that full auctioning of carbon permits to new entrants is the logical policy to follow in order to reduce emissions structurally, and, as a result, we believe that sooner or later it will be introduced. In our view, therefore, any rational investor would plan a 40-year investment on the basis of this eventuality.
5. that the plant runs baseload (i.e. a load factor of 86%, or 7,500 hours) for the first 18 years of its life and then at a load factor of 40% for its remaining life. We would note that this may be a generous assumption for coal and lignite relative to gas because if the cap were to tighten aggressively over the next 20 years then other things being equal we would expect the gas plant to run at a higher load factor than the coal and lignite plants over the last 20 years of its operating life.
6. that the required rate of return is 9.6% pre-tax real, corresponding to a post-tax ROCE of 6.7% assuming 25% equity finance.

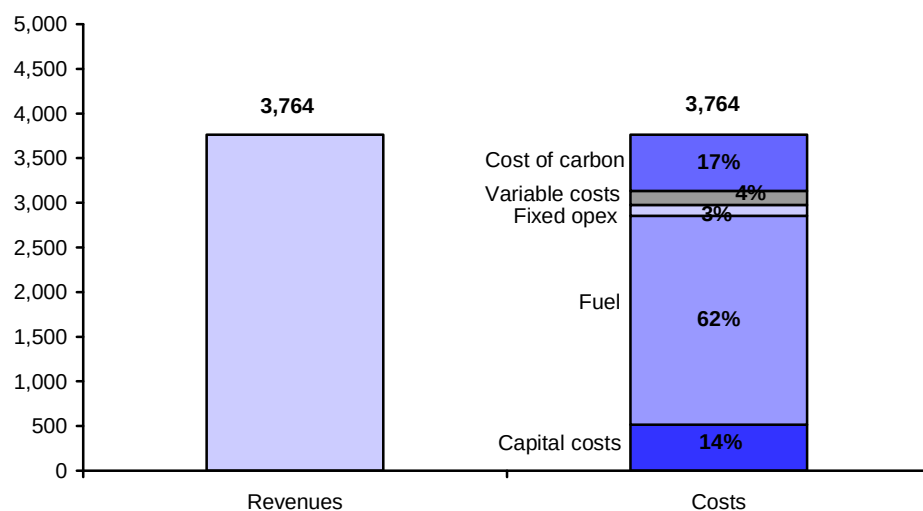
The economics of a new gas plant with 100% carbon purchase

Figure 4 sets out our key assumptions for a new gas plant regarding capital costs, fuel costs, and fixed and variable operating costs. The key assumptions we make for gas relative to coal and lignite concern fuel costs, efficiency rates, and fixed operating costs. We assume a gas price of Euro 5.35/GJ on the basis of the thermal equivalency to the DB medium-term oil-price forecast of \$44/boe, an efficiency rate of 57%, and fixed operating costs of Euro 12/kw.

Figure 4: Key assumptions for a new gas plant

Variable	Assumption
Capital cost	Euro 563,000/MW
Capacity	1,000MW
Capital outlay	Euro 563m
Required return (pre-tax real)	9.6%
Oil price	\$44/boe
Gas price	Euro 5.35/GJ
Efficiency rate	57%
Gas price	Euro 33.8/MWh
Fixed operating costs	Euro 12/kw
Variable operating costs	Euro 2.25/MWh
Carbon price	Euro 25/tonne
Carbon intensity	0.365
Load factor for first 18 years	86%
Annual output for first 18 years	7.5TWh
Load factor for remaining 22 years	40%
Annual output for remaining 22 years	3.5TWh
Power price necessary to earn required return	Euro 54.3/MWh

Source: Deutsche Bank

Figure 5: Breakdown of costs for a new gas plant (Euro m)

Source: Deutsche Bank

On the basis of all these assumptions, we calculate that a new gas plant would earn its required rate of return with a power price of Euro 54.3/MWh.

Figure 5 sets out the breakdown of total costs against total revenues for a new gas plant based on the assumptions in our model.

For a gas plant, fuel costs are by far the most important component, accounting for 62% of total costs. Carbon and capital costs account for 17% and 14% respectively, but fixed and variable operating costs are negligible.

The economics of a new conventional coal plant with 100% carbon purchase

Figure 4 sets out our key assumptions for a new coal plant regarding capital costs, fuel costs, and fixed and variable operating costs.

The key assumptions we make for coal relative to gas and lignite concern fuel costs, efficiency rates, and fixed operating costs. We assume a coal price of Euro 177.5/GJ on the basis of a medium-term coal-price forecast of \$60/tonne, an efficiency rate of 47%, and fixed operating costs of Euro 45/kw.

On the basis of all these assumptions, we calculate that a new coal plant would earn its required rate of return with a power price of Euro 58.5/MWh.

However, if a new gas-plant could earn its return at Euro 54.3/MWh, then rational investors would build gas ahead of coal, and a coal plant built under these assumptions would then receive the new-entrant gas price of Euro 54.3/MWh.

Figure 7 sets out the breakdown of total costs against total revenues for a new coal plant based on the assumptions in our model and assuming it receives the new-entrant gas price of Euro 54.3/MWh.

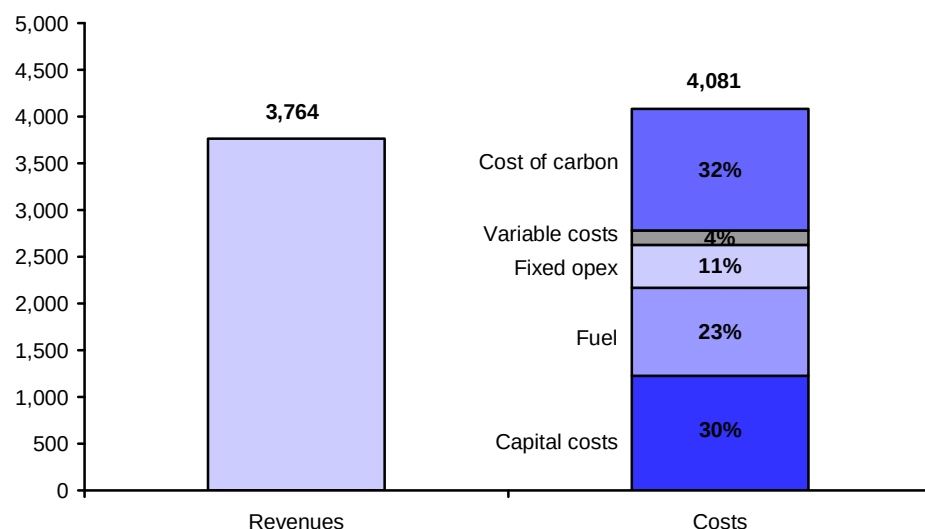
For a coal plant, carbon and capital costs are the most important components, accounting for 32% and 30% respectively of total costs. Fuel costs account for 23%, fixed costs for 11%, with variable costs negligible.

Figure 6: Key assumptions for a new conventional coal plant

Variable	Assumption
Capital cost	Euro 1,313,000/MW
Capacity	1,000MW
Capital outlay	Euro 1,313m
Required return (pre-tax real)	9.6%
Coal price	\$60/tonne
Coal price	Euro 1.78/GJ
Efficiency rate	47%
Coal price	Euro 13.6/MWh
Fixed operating costs	Euro 45/kw
Variable operating costs	Euro 2.25/MWh
Carbon price	Euro 25/tonne
Carbon intensity	0.75
Load factor for first 18 years	86%
Annual output for first 18 years	7.5TWh
Load factor for remaining 22 years	40%
Annual output for remaining 22 years	3.5TWh
Power price necessary to earn required return	Euro 58.5/MWh

Source: Deutsche Bank

As can be seen, under this scenario, a new coal plant would not earn its required return, but rather would destroy just over Euro 300m of value, or approximately 25% of the capital invested.

Figure 7: Breakdown of costs for a new coal plant (Euro m)

Source: Deutsche Bank

The economics of a new lignite plant with 100% carbon purchase

Figure 8 sets out our key assumptions for a new lignite plant regarding capital costs, fuel costs, and fixed and variable operating costs.

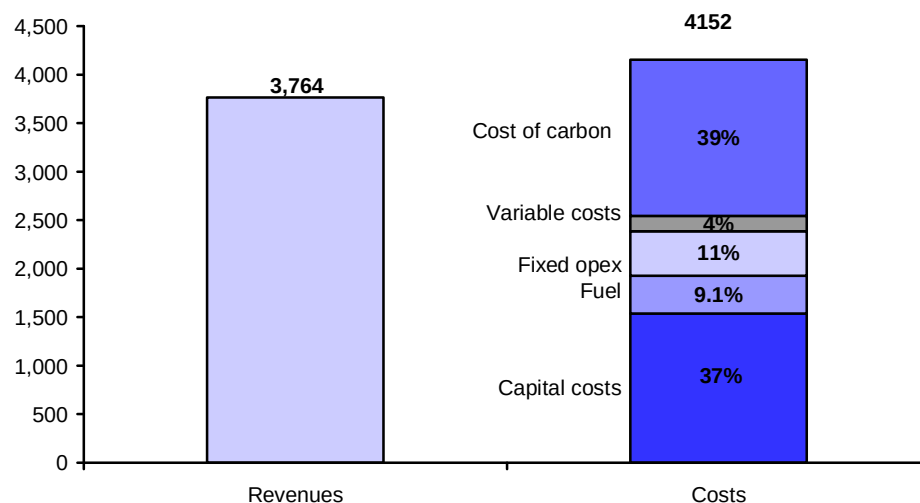
Figure 8: Key assumptions for a new lignite plant

Variable	Assumption
Capital cost	Euro 1,650,000/MW
Capacity	1,000MW
Capital outlay	Euro 1,650m
Required return (pre-tax real)	9.6%
Lignite price	Euro 0.7/GJ
Efficiency rate	45%
Lignite price	Euro 5.6/MWh
Fixed operating costs	Euro 45/kw
Variable operating costs	Euro 2.25/MWh
Carbon price	Euro 25/tonne
Carbon intensity	0.93
Load factor for first 18 years	86%
Annual output for first 18 years	7.5TWh
Load factor for remaining 22 years	40%
Annual output for remaining 22 years	3.5TWh
Power price necessary to earn required return	Euro 59.5/MWh

Source: Deutsche Bank

The key assumptions we make for lignite relative to gas and coal again concern fuel costs, efficiency rates, and fixed operating costs. We assume a lignite price of Euro 0.7/GJ, an efficiency rate of 45%, and fixed operating costs of Euro 45/kw (the same as for hard coal).

On the basis of all these assumptions, we calculate that a new lignite plant would earn its required rate of return with a power price of Euro 60/MWh.

Figure 9: Breakdown of costs for a new lignite plant (Euro m)

Source: Deutsche Bank

As with coal, however, if a new gas-plant could earn its return at Euro 54.3/MWh, then rational investors would build gas, and a lignite plant built under these assumptions would then receive the new-entrant gas price of Euro 54.3/MWh.

Figure 9 sets out the total costs against revenues for a new lignite plant assuming it receives the new-entrant gas price of Euro 54.3/MWh.

For a lignite plant, carbon and capital and costs are by far the most important components, accounting for 39% and 37% respectively of total costs. Fixed operating costs are the next most important at 10% of the total, but fuel costs are low at only 9%, with variable costs again negligible.

As can be seen, under this scenario, a new lignite plant would not earn its required return, but rather would destroy just over Euro 313m of value, or approximately 25% of the capital invested.

Conclusion: gas is the new entrant of choice with carbon above Euro 15/tonne

Our example above is, of course, based on a number of key assumptions, and changing these assumptions could change the relative attractiveness of the various fossil fuels as new entrants. In particular, given the much greater sensitivity of coal and lignite than gas to the carbon price, changing this one variable can radically alter the attractiveness of coal and lignite.

For example, if we had assumed a carbon price of Euro 15/tonne in our scenarios above, as opposed to Euro 25/tonne, then there would be little to choose between gas and coal: gas would earn its required return at Euro 50.7/MWh, and coal at Euro 51/MWh. In an environment of lower carbon prices with all our other assumptions unchanged, then, coal would, at first sight at least, appear to be a real competitor to gas.

However, we would make two points in conclusion that seem to us decisive regarding the merits of gas relative to coal and lignite in a carbon-constrained world:

- First, the whole logic of the ETS and the Kyoto Protocol to which it is linked is to send a signal via the carbon price regarding what kind of investments should be made today so that carbon emissions are structurally lower over the next 30-40 years.

In other words, the carbon price is not just a short-term indicator designed to enable companies and countries to comply with their short-term emissions limits (after all, these are somewhat arbitrary in any case). On the contrary, it is also – and more importantly – a long-term indicator designed to encourage the right investments to be made so that emissions are reduced much more significantly over the long term.

In our view, this means that any rational investor should work on the assumption that policymakers will seek to engineer a carbon price that will encourage lower-carbon investments to be made, because that is exactly what the logic of the ETS and the Kyoto Protocol dictate that they do. We think our carbon-price forecast over 2008-12 of Euro 25/tonne is consistent with this policy objective, but gas already looks like the new entrant of choice at Euro 15-20/tonne in any case.

As a result, while there is certainly an argument for building some new coal plant based on the need to have a diversified portfolio of plant and the fact that commodity prices could change over time in a way that favours coal relative to gas (though equally, of course, prices could develop in a way that favours gas relative to coal), we would assume that at a carbon price of Euro 15/tonne or above gas would ordinarily be the predominant new-entrant fuel of choice.

- Second, in our scenarios above, we assume the same carbon price for gas, coal, and lignite, as well as the same load factors for each, as this is the only way to compare the relative economics of each fuel. In reality, however, it should be clear that if gas were more competitive at a carbon price of Euro 25/tonne then rational investors would build as many gas plants as were required to meet demand.

This means that if anybody went ahead with a new coal or lignite plant under this scenario, then either it would not be able to run baseload, or, if it did run baseload, it would push the equilibrium carbon price up to a higher level than Euro 25/tonne. The point in either case is that in reality the economics of building a new coal or lignite plant would be even worse than our modelling above suggests.

(As we explain below in Section 4, this means that even allowing for the fact that the Commission will allow 100% free allocation to new entrants for the duration of Phase 2 of the ETS for any plants that starts its operations over that period, gas will be the new entrant of choice over 2008-12. This is because although coal looks competitive to build against gas if it gets five years' worth of free carbon – even at the carbon price of Euro 25/tonne we assume over the rest of the plant's lifetime – the reality is that the very act of building a new coal plant would push up the equilibrium carbon price beyond Euro 25/tonne and hence make it less competitive relative to gas.)

In short, at a carbon price of Euro 15/tonne or above gas looks to us to be the predominant new-entrant fuel of choice. As a result, in a carbon-constrained world where the carbon cap can be expected to tighten incrementally over time, we think conventional coal and lignite plants would require subsidies equivalent to at least 25% of their capital costs to make them competitive with gas, and that this is what the 4+14 and 4+10 rules would have amounted to.

Problem 2: the 4+14 rule exempted some new plant from the ETS

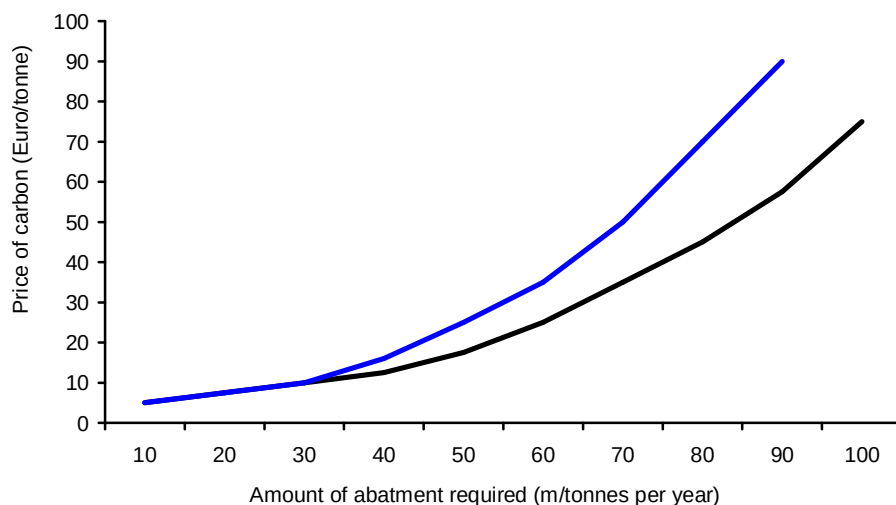
A second major problem with the 4+14 rule is that it would have led to higher carbon prices across the EU than would otherwise have been the case, both during the trading period in which the plants that made use of these rules came into operation and in future trading periods.

This is because the carbon allowances that a limited number of new entrants (would have received under this rule) would not have been tradable. Rather, they would have received what we might term “must-run” permits after the event, that is to say with new entrants claiming the number of allowances they needed on an *ex-post* basis once they knew what their output was. In other words, these new entrants – albeit a limited amount of capacity in total (1,000-2,00MW, on our estimates) -- would have been exempted from the ETS.

As a result, there would have been no incentive for these new entrants with must-run permits to adjust their output in response to the changing market value of carbon, because they would not have had any opportunity cost to take into account. On the contrary, they would have had every incentive to maximize their output of electricity – and hence of emissions – because they would incur no extra cost in the process. In effect, they would have been given a blank cheque in terms of their emissions.

As a result, the 4+14 rule would have resulted in more expensive abatement options being found to meet the same cap. The point to make here is that the more plant that receives non-tradable permits, the more limited is the supply of abatement options. So, for a given carbon cap, exempting some plant from the ETS results in a steeper supply curve than would be the case if all plant were given tradable permits. Figure 10 shows this schematically.

Figure 10: Stylised representation of carbon-abatement supply curves



Source: Deutsche Bank

Moreover, because the plant that would have received must-run permits under the 4+14 rules would have been guaranteed allowances beyond the trading period during which they came into operation, this would have prevented the most efficient generation schedule from being constructed in future trading periods as well. And because the ETS is a pan-European market, this means that the possibilities for fuel switching not just in Germany but across the EU as a whole over 18 years would have been more limited.

Problem 3: the 4+14 rule would have lead to super-normal profits for a limited number of new entrants

Under the 4+14 rule, the limited amount of plant that received must-run permits would have earned a return well above its required rate. Figure 11 shows our estimate of the cost of building new coal and lignite plants with free carbon for the first 18 years but thereafter paying for all carbon allowances at our assumed price of Euro 25/tonne.

On our calculations, coal with free carbon for 18 years would require a price of Euro 41.5/MWh, and lignite only Euro 38.3/MWh.

Figure 11: Estimated economics of a new lignite plant with no carbon costs for the first 18 years

Variable	Coal new entrants	Lignite new entrants
Carbon price for first 18 years	0	0
Carbon price for remaining 22 years	Euro 25/tonne	Euro 25/tonne
Power price necessary to earn required return	Euro 41.5/MWh	Euro 38.3/MWh

Source: Deutsche Bank

Putting it another way, coal would require free permits for only six years (i.e. 4+2) to make it competitive with gas, while lignite would have required free permits for only 8 years (4+4).

However, given that it is now rational to expect an incremental tightening of the cap in future trading periods as policymakers look to reduce emissions dramatically over coming decades, the market would have wanted to see less carbon-intensive power plants being commissioned that would be free to price the market value of carbon into their cost bases in future trading periods.

In reality, then, had the 4+10 rules been allowed to stand, the limited amount of new plant that would have received must-run permits for the first 18 years would have made significant economic rent, because the long-term power price would still have had to reach the level at which it became rational to invest in a new gas plant with the cost of carbon allowances over the plant's lifetime fully priced in. This is because this would be the only way of ensuring that the right plant was built for more tightly constrained future trading periods.

We conclude that guaranteeing free carbon for new entrants would not have lead to lower long-term prices as policymakers might have hoped, because other things being equal prices would still have had to reach new-entrant levels for gas with the cost of carbon fully included.

As a result, any new-entrant plant commissioned under the 4+14 rules that did ultimately receive 18 years' worth of free allowances while also receiving the long-term power price for its output would have earned significant super-normal profits.

Problem 4: discriminating in favour of new entrants at the expense of incumbents

A further problem created by the 4+14 rule is the fact that it would have favoured new entrants at the expense of incumbent generators. This is because the new entrants would have been exempted from the ETS for the first 18 years, whereas incumbents would have had to live with the consequences of an incrementally tighter cap over time.

This would have left new entrants open to two costs that new entrants would not have faced for the first 18 years:

1. At the start of each future trading period incumbents would have faced the prospect of a tighter cap and hence a reduced number of permits available to them.
2. It seems reasonable to assume that in future trading periods incumbents will have to pay for a greater proportion of their declining allocations via auctioning. (Indeed, it is not impossible that they may have to pay for 100% of their permits from as early as 2013).

As a result, had the 4+14 rule been allowed to stand, the subsidy new entrants would have received would have effectively been funded via a wealth transfer from incumbents. This is because the permits that had been guaranteed to new entrants for future trading periods would have had to come out of the same pool available for incumbents, a pool that would decline progressively with each new trading period. A fixed allocation for new entrants for the first 18 years would therefore have resulted in their receiving an ever greater proportion of an ever smaller pool. It follows that incumbents, by contrast, would have faced ever lower future allocations in both absolute and relative terms, while also being asked to pay for a larger number of these reduced allocations in both absolute and relative terms.

Ironically, this would have been all the less justifiable given that the incumbent plant would have been built under very different assumptions, namely at a time when there was no carbon cap to worry about and hence no opportunity cost to take into account when making the investment decision. (It is worth noting that this is probably why the ETS Directive stipulated that the overwhelming majority of allowances in Phase 1 and Phase 2 of the scheme – 95% and 90% respectively – should be allocated free of charge.)

By contrast, new entrants today know full well that a carbon cap exists and that logic dictates it will become ever tighter over time. In such circumstances, what economic justification can there be for subsidising carbon-intensive new entrants?

Conclusion: why the 4+14 rule had to go

Our analysis above indicates that the 4+14 rule would have subsidised the construction of new coal and lignite plants that would have reduced the supply of abatement options and thereby lead to higher carbon prices in the EU over 18 years than would otherwise have been the case. In the process, a limited number of new entrants would have earned supernormal profits with must-run permits.

So why did the German Government propose this rule in the first place? As the Commission indicated in its ruling of 29 November 2006 on Germany's Phase-2 NAP, the German Government argued that it arose out of the need to balance environmental factors with the need for planning certainty on the part of investors. This is how the Commission characterised the German defence of the 4+14 rule on page 12 of its verdict on the NAP (available at www.ec.europa.eu/environment/):

“According to Germany, this different treatment is notably justified on the grounds that the emissions trading periods are not identical with the investment cycles of installations and, therefore, allocation guarantees for future trading periods create the necessary balance between environmental objectives and the need for investors to have planning certainty, thus accelerating investment decisions for new installations and the change towards new technologies.”

In reality, however, this argument is just another way of admitting that without the guarantee of free carbon permits in future trading periods, certain kinds of plant – notably, ones that are very carbon intensive but that would have the virtue of preventing too great a future dependence on imported gas – would not get built. The Commission's ruling recognised this when it went on to say (*Ibid*):

“The Commission, however, does not agree with Germany's reasoning and maintains that all otherwise comparable existing installations need to be treated in the same manner. (...) There is no trade-off of individual investment decisions with the environmental objectives of the Community scheme, which are notably achieved through the economic incentives to reduce emissions created by the scheme for all installations.”

As a result, the Commission's view is that it is only legitimate to give special treatment to new entrants in the trading period during which they commence operations (*Ibid*):

“The Commission acknowledges only that existing installations and new entrants, which are recognised as a separate category under the Directive, may be allocated on the basis of a different methodology during one given trading period. Such different treatment can however not be justified once a new entrant in the preceding trading period turns into an existing installation in the following trading period with similar data material being available as for other existing installations. ”

All of which means that Germany now has to find an alternative way of balancing the need to ensure security of supply against the objective of reducing future emissions. Moreover, this alternative is required very urgently, since under current legislation Germany's emissions from power generation, far from decreasing, will actually increase dramatically over the next 15 years.

2. Germany's current energy policy is untenable

Under current legislation, 20GW of nuclear capacity will be phased out in Germany by 2022, and if this actually happens we estimate that a total of 42GW of new plant will be required by 2020. This assumes 20GW to replace withdrawn nuclear plants, 12GW to meet organic demand growth while ensuring a minimum reserve margin of 10%, and 10GW to replace old, inefficient fossil-fuel plant.

Under this scenario, we estimate that CO₂ emissions from the power-generation sector would increase by 16% between 2010 and 2020 (to 293m tonnes from 250m tonnes), and that Germany would therefore find it impossible to meet its policy aspiration of a 40% cut in GHG emissions by 2020 against 1990 levels. Moreover, gas used for power generation would increase by 260% over 2005-2020, to 503TWh from 140TWh, thus dramatically increasing Germany's dependence on foreign energy supplies.

So, far from reducing CO₂ emissions and securing future energy supplies, current policies would increase both Germany's emissions and its dependence on foreign gas imports.

Germany has ambitious plans to reduce its carbon emissions ...

Under the Kyoto Protocol, Germany has a legally enshrined target for reducing carbon emissions over 2008-12 by 21% against 1990 levels, but it aspires to go much further than this beyond 2012. On 13 November last year, in a press release issued by the German Environment Ministry, the Environment Minister, Sigmar Gabriel, set out some very ambitious targets for future emissions reductions:

"We are ready to launch negotiations with all countries immediately. The German Government will advocate the European Union taking on a pioneering role in international climate policy and reducing its greenhouse gas emissions by 30% by 2020 compared with 1990 levels. In my view, this means that Germany will have to contribute a 40% reduction, because other countries in Europe with weaker economic development cannot manage large reductions."

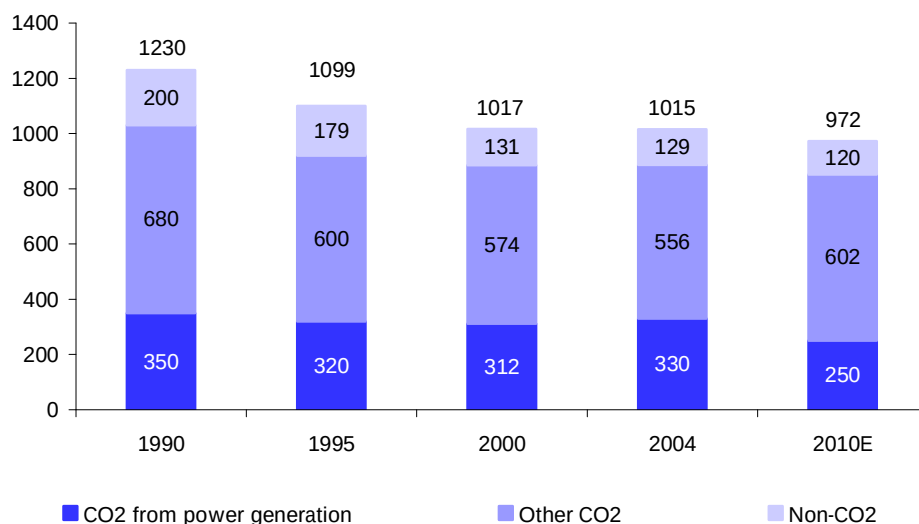
This press release coincided with Mr. Gabriel's intervention at the United Nations conference on climate change in Nairobi, and it reinforced the view that had been expressed by Germany's Federal Environment Agency – a body that provides scientific and technical support to the Environment Ministry – a month earlier in a press release on 17 October. However, the Federal Environment Agency set out aspirations for reducing emissions not just out to 2020, but to 2050 as well:

"The FEA considers reducing greenhouse gas emissions in Germany by 40% by 2020 and by 80% by 2050 compared to 1990 to be technically feasible and economically sensible."

So the German Government and the specialist technical agency that advises it on all matters environmental consider a 40% reduction in emissions by 2020 to be desirable, while the Environment Agency thinks that a reduction of 80% by 2050 would be feasible. However, reductions in emissions on this scale are inconceivable without continuing significant reductions in the emissions of the power-generation sector over time.

To put these ambitions into context it is useful first of all to consider the emissions reductions already achieved by Germany since 1990. Figure 12 shows total greenhouse-gas (GHG) emissions, total CO₂ emissions, and CO₂ emissions from power generation since 1990, together with the targeted trajectory to 2010E based on Germany's Phase-2 NAP.

Figure 12: GHG emissions in Germany, 1990-2010E (mT/CO₂e)



Source: German Government, Deutsche Bank estimates

The chart shows that Germany's total GHG emissions in 1990 were 1.23bn tonnes per year of CO₂-equivalent (CO₂e), of which 1.03bn tonnes were CO₂ itself. Of this 1.03bn tonnes, 350m were from power stations, so CO₂ emissions from the power sector accounted for 34% of total CO₂ emissions and 29% of total GHG emissions in 1990. By 2004, Germany's total GHG emissions had fallen by 17.5% to 1.015bn tonnes, and total CO₂ emissions by 14% to 886m tonnes. However, CO₂ emissions from power stations had fallen only 6%, to 330m tonnes.

Looking forward, the bar for 2010 shows the German Government's target for total GHG emissions annually over 2008-12, as set out in its NAP for Phase 2 of the ETS. Germany's Kyoto target is 972m tonnes of CO₂e in GHG emissions per year over this period, so we have taken 2010E as being representative of this timeframe overall. Based on the top-down allocations originally proposed in Germany's Phase-2 NAP, and the Commission's subsequent insistence that Germany reduce its proposed allocations by 29m tonnes per year, we estimate that the power-generation sector will ultimately receive some 250m tonnes of allowances per year over 2008-12.

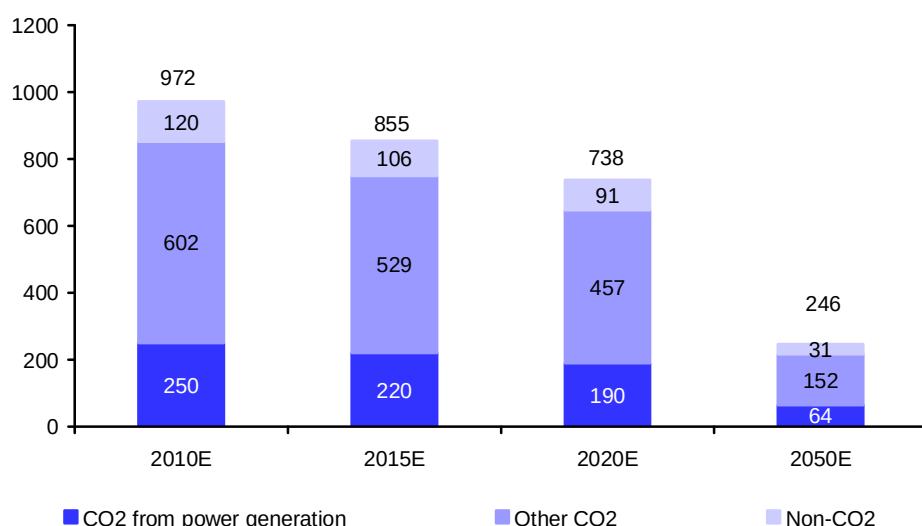
In other words, by 2010 the power sector's emissions are expected to have fallen by almost 30% relative to their 1990 level, total CO₂ emissions by 17%, and total GHG emissions by 21%. Policymakers are therefore putting a disproportionately large share of the burden for achieving Germany's Kyoto targets on the power sector, even if in order to achieve these targets the power sector will in practice rely to some extent on offsetting emissions via the purchase of Kyoto credits rather than reducing emissions domestically.

Figure 13 then sets out the future cuts in emissions implied by the aspirations voiced by the Environment Minister and the Federal Environment Agency quoted above. To calculate these implied cuts, we take the reductions aspired to by 2020 and 2050 in the recent pronouncements of the Minister and the Agency, and assume that from 2010 the reduction for the power sector is of the same relative magnitude as for the economy as a whole.

So, whereas the power sector faced a steeper reduction over 1990-2010 than the economy as a whole, we assume that the required reduction from 2010 levels to 2020 and 2050 is a uniform 24% and 75% respectively across the whole economy. Again, we are assuming here that all the reductions are achieved domestically, because even if in practice part of the target will likely be achieved via the purchase of offset credits, we think there will be an ever stronger political imperative to achieve the majority of cuts domestically.

This is partly because if the EU continues to build new carbon-intensive plants today with a view to 'buying compliance' via offsets from developing countries in future it might prove difficult to get the larger developing countries like China and India to sign up to emissions limits of their own (a key policy objective for the EU), and partly because the cheapest offset options will be taken earliest in any case (i.e. over 2008-12).

Figure 13: GHG-emissions reductions aspired to by Germany, 2010-50 (m/T)



Source: German Government, Deutsche Bank estimates

If Germany meets its Kyoto targets, then emissions will have fallen by 21% in total over the 20 years 1990-2010, but it should be remembered that in the 1990s there was a large one-off benefit in the country's emissions trend owing to the hollowing out of much of east German industry in the wake of reunification. This largely explains the dramatic reduction in emissions shown in Figure 12 above between 1990 and 2000, and the much gentler declining trend over 2000-2010.

Without any such one-off benefits to be expected over 2010-50, the scale of the cuts that policymakers are now aspiring to over the next 15-40 years is therefore all the more challenging. Such targets will only have credibility if all economic decision-makers are incentivised in a way that ensures the opportunity cost of carbon is reflected not only in all short-term pricing decisions, but also – and more importantly – in all long-term investment decisions (as explained in Section 1 above, the fact that the 4+14/4+10 rules would have prevented the cost of carbon from being taken into account in planning new power stations is why they were fundamentally flawed).

However, even though the rejection of the 4+14/4+10 rules should ensure that power plants built in future take the opportunity cost of carbon into account, there is still another very serious handicap currently preventing Germany from having any serious prospect of achieving significant cuts in its carbon emissions over 2010-2050. This handicap is the policy to phase out all nuclear power over the next 15 years.

... but currently plans to phase out nuclear power by 2022

In 2000, the German Government passed a law to phase out all nuclear power stations after the equivalent of 32 years' operating life, granting a set number of hours per station according to a standardized load factor over 32 years.

This is well below the standard operating life of 40 years that was assumed when these PWR (pressurized-water reactor) and BWR (boiling-water reactor) stations were built, and barely more than half the 60 years' life of which they are technically capable after additional capex, and which has been granted to over 30 PWR and BWR stations in the US in recent years.

Figure 14 sets out the number of remaining TWh of output granted to each station under the so-called nuclear-consensus law from 1 January 2000, together with the output left as at 31 July 2006 after updating for production in the intervening period.

Figure 14: The expected phase-out of nuclear power stations in Germany, 2007E-2020E.

PLANTS STILL OPERATING	Start date	Capacity (MW)	Remaining allowed output (TWh)		Assumed number of years left date	Original scheduled closure date
			As at 1 January 2000	As at 31 July 2006		
Biblis A*	1974	1,167	62.0	14.9	1	2008E
Neckarwestheim 1	1976	785	57.3	17.7	3	2009E
Biblis B**	1976	771	81.5	26.0	3	2009E
Brunsbüttel	1976	1,240	47.7	16.3	4	2010E
Isar 1	1977	878	78.4	34.2	5	2011E
Unterweser	1978	1,345	118.0	56.7	6	2012E
Philippsburg 1	1979	890	87.1	38.7	7	2013E
Grafenrheinfeld	1982	1,275	150.0	84.2	8	2014E
Grundremmingen B	1984	1,284	160.9	94.8	9	2015E
Grundremmingen C	1984	1,392	168.4	103.2	10	2016E
Krümmel	1983	1,284	158.2	97.8	11	2017E
Philippsburg 2	1984	1,288	198.6	129.4	12	2018E
Grohnde	1984	1,360	200.9	129.5	12	2018E
Brokdorf	1986	1,370	217.9	144.7	13	2019E
Emsland, Lingen	1988	1,329	230.1	157.7	14	2020E
Isar 2	1988	1,400	231.2	155.6	14	2020E
Neckarwestheim 2	1989	1,269	236.0	166.9	16	2022E
TOTAL		20,327	2484.2	1468.3		
PLANTS CLOSED DOWN	Start date	Capacity	As at 1 January 2000	As at 1 July 2006		
Obrigheim	1974	340	8.7	0		
Mühlheim-Kärlich***	1976	1,302	107.3	107.3		
Stade***	1976	672	23.2	4.8		
TOTAL		2,314	139.2	112.1		
TOTAL		22,641	2623.4	1580.4		

Source: German Government, Deutsche Bank estimates. *Given the ongoing outage from Q4 of 2006, Biblis A may not now close until 2009E; **With approx. 20TWh of transferred output from Mühlheim-Kärlich, Biblis B will in practice probably not shut until 2011E;***The re-allocation of a large part of this production has yet to be decided. In practice this means that, like Biblis B, some of the other plants here will close later than their own remaining output alone would imply.

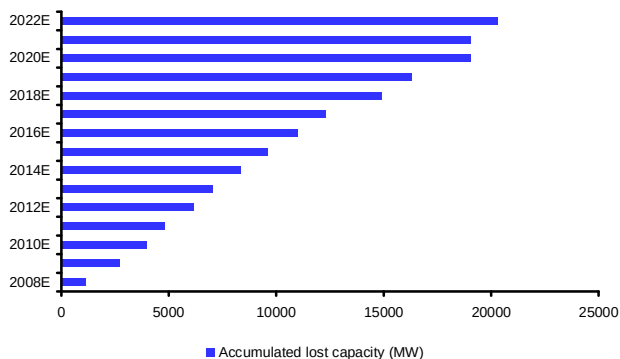
In total, the law provided for Germany's total nuclear capacity of 22.6GW to be closed down, giving a total remaining allowed output of 2,623TWh from 1 January 2000. This comprised 2,484TWh from stations still running today, and 134TWh from stations that were closing just at the time the law was passed or that have closed since (where, in both cases, some of the output from these stations was allowed to be transferred to other stations).

By 31 July 2006, the total amount of remaining output had declined to 1,580TWh, giving total production of 1,015TWh in the intervening six years and seven months. This equates to an annualized average output of 156TWh per year since January 2000.

As at the beginning of 2007, the total remaining nuclear capacity is 20.3GW, with total remaining output of approximately 1,515TWh after allowing for the production over August-December 2006. Assuming 156TWh per year, this would give just under 10 years of nuclear production remaining, but in practice the decline will be a more gradual one, in line with the scheduled closure dates of the stations left.

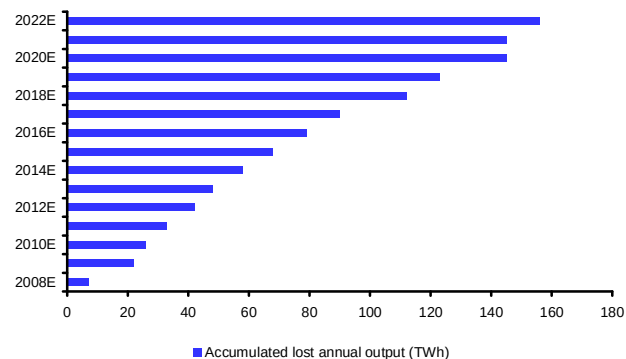
Figure 15 shows estimated accumulated capacity closures and Figure 16 of accumulated lost annual output over 2007-2022. We estimate that the last nuclear station will close in 2022, but that capacity and output will halve against current levels by 2015E/16 (this is before taking into account the 112TWh to be transferred from Mülheim-Kärlich and Stade).

Figure 15: Expected closure of Germany's nuclear capacity (MW)



Source: German Government, Deutsche Bank estimates

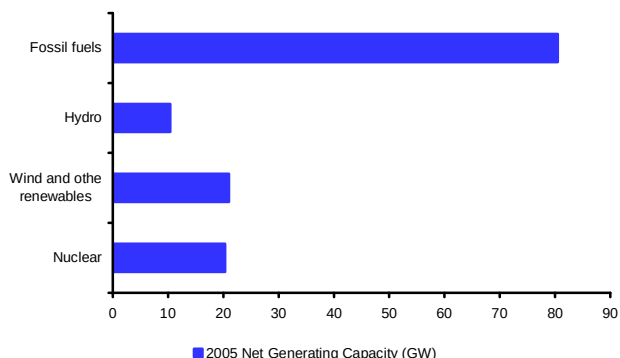
Figure 16: Expected lost nuclear output in Germany (TWh)



Source: German Government, Deutsche Bank estimates

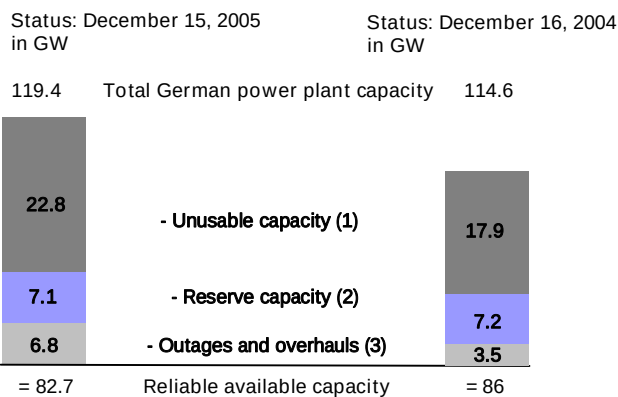
To put these planned closures into context, it is useful to look at nuclear power as a proportion of total available capacity. According to Eurelectric, in 2005 Germany had a total maximum net generating capacity of 132.3GW (Figure 17), while the Association of German Power Grids (the VDN) gives a slightly lower number of 119.4GW (Figure 18). This would mean that Germany's nuclear stations accounted for 15%-17% of the total in 2005.

Figure 17: Total generation capacity in Germany, 2005 (GW)



Source: Eurelectric

Figure 18: Reliable available capacity in Germany, 2005 (GW)



Source: VDN, RWE

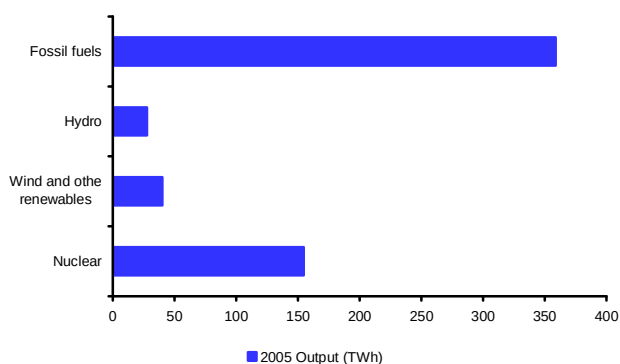
In reality, however, this understates the true proportion of capacity accounted for by nuclear, because much of the capacity theoretically available is not reliable at all times.

For example, Germany has the largest amount of wind capacity in the world (approximately 15GW) and the availability of wind power is much lower than for other kinds of generation as it depends on the weather. As a result, once adjustments are made for unusable capacity, reserve capacity, and outages, the real figure for reliable available capacity is much lower. As shown in Figure 18, on VDN's estimates the 'real' number for total German capacity in 2005 would be 82.7GW.

In reality, therefore, we would estimate that nuclear accounts for about 25% of total firm capacity at the moment, which, as Figure 19 shows, is in line with its share of output (155TWh out of 581TWh in 2005, or 26%). As a result, phasing out 20.3GW of nuclear capacity over the next 15 years raises obvious questions about Germany's capacity margins going forward, especially as these are already below the 10% level generally regarded as an indication that new plants are needed in order to prevent future blackouts.

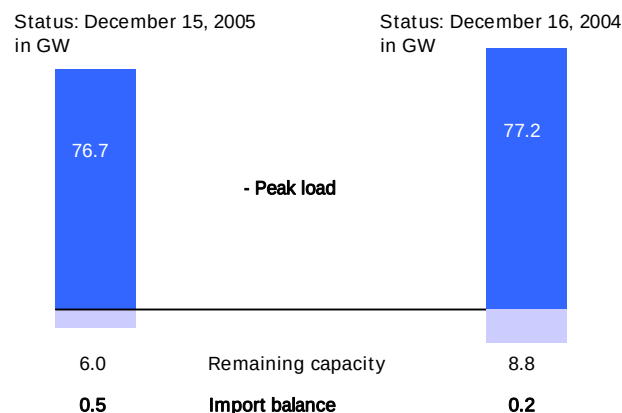
Figure 20 shows the reserve margin in 2005. With peakload of 76.7GW, there was 6GW of further reliable capacity available, giving a reserve margin of 8% (i.e. 6/76.7). This means that a further 2.5GW of reliable capacity would be required as of today just to bring Germany back to the 10% reserve margin generally regarded as the minimum prudent level.

Figure 19: German power output by source, 2005 (TWh)



Source: Eurelectric

Figure 20: Germany's capacity margin, 2005 (GW)

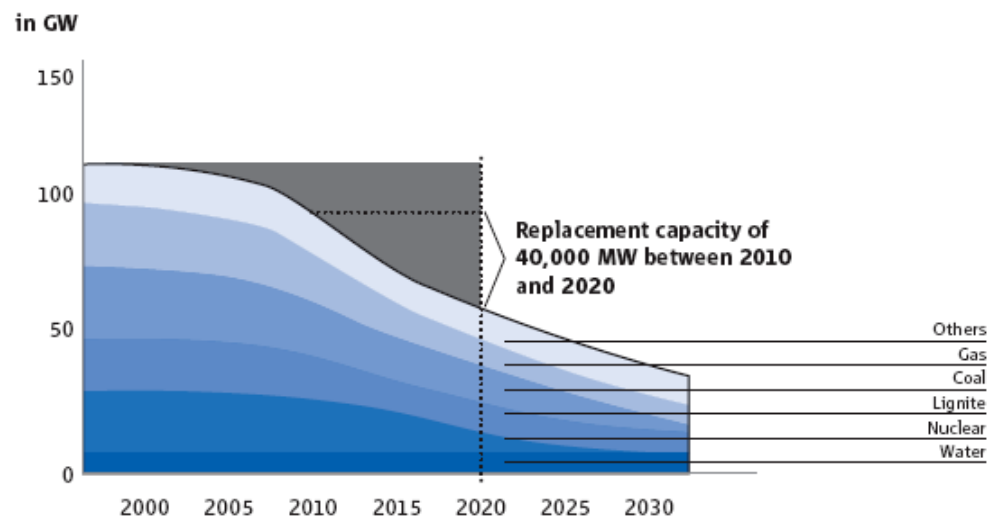


Source: VDN, RWE

The phase-out of nuclear power and returning to a capacity margin of at least 10% will clearly precipitate a very large new-build programme over the next 10-15 years, but the capacity problem in Germany over the next decade and a half will be aggravated by two other factors:

1. In addition to the loss of 20GW of nuclear power, a further 20GW of fossil-fuel fired plant would come off line over 2010-2020 if we were to assume that all power plants were replaced after 40 years' operating life. Figure 21 shows the total amount of plant that would come off line by 2020E assuming the phase-out of nuclear, and that all fossil-fuel plants are replaced after 40 years.
2. Even in a mature economy such as Germany, organic growth in demand can be expected to increase the peak-load capacity requirement over time. Although we would expect the rate of increase to be clearly below the trend-rate of growth in GDP, assuming a range in annualised growth in peak-load demand over 2007E-2020E of only 0.5%-1% would still give rise to a need for 6.6GW-13.6GW of new capacity by 2020E (Figures 22 and 23).

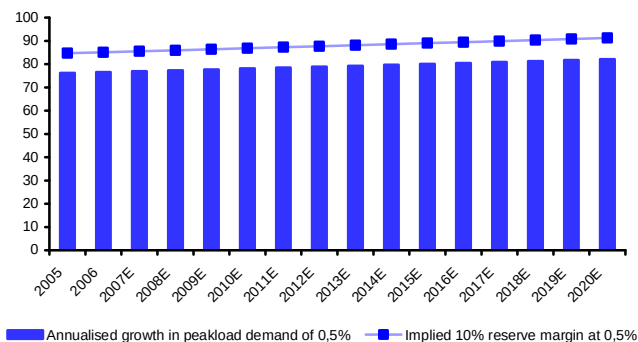
Figure 21: Potential capacity withdrawals in Germany, 2010E-2020E (GW)



Source: VGB PowerTech e.V

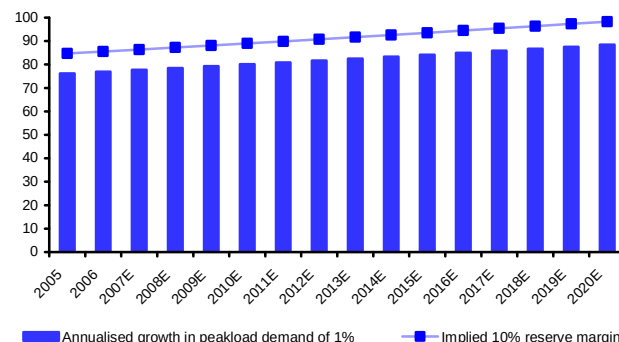
Figures 22 and 23 assume that capacity levels have to rise by an initial 2.5GW to bring the reserve margin back to the desired 10% level, and that capacity then grows over time in line with the need to maintain this ratio assuming annual growth in peak-load demand of 0.5% and 1% respectively.

Figure 22: New capacity required to maintain 10% reserve margin at 0.5% growth, 2005-20E (GW)



Source: VDN, RWE, Deutsche Bank

Figure 23: New capacity required to maintain 10% reserve margin at 1% growth, 2005-20E (GW)



Source: VDN, RWE, Deutsche Bank

In short, assuming that Germany aims to re-establish a reserve margin of 10% against a backdrop of 0.5%-1% growth in peak-load demand over the next 15 years, that the nuclear phase-out goes ahead, and that all fossil-fuel plants are replaced after 40 years, then total capacity required by 2012 would be 18-21GW, and by 2020 49GW-56GW (Figure 24).

Figure 24: Total potential new capacity required in Germany over 2010E-2020E (GW)

Motive for building new capacity	2012E	2012E-2020E	TOTAL BY 2020E
Amount required to re-establish a capacity margin of 10%	2.5	0.0	2.5
Annualised organic growth in peak-load demand (0.5%-1%)	3.0-6.1	3.6-7.5	6.6-13.6
Nuclear phase-out	6.2	14.1	20.3
Withdrawal of fossil-fuel plants after 40 years' operating life	6.5	13.5	20.0
TOTAL	18.2-21.3	31.2-35.1	49.4-56.4

Source: Deutsche Bank

However, in our view this is a hypothetical scenario, because there are two important caveats to enter regarding the 20GW of fossil-fuel plant:

1. In reality, we think much of this plant is likely to be economically and technically viable beyond the 40-year lifespan assumed in Figures 21 and 24.
2. Replacing the plant that is not economically or technically viable beyond 40 years with new plants would lead to an increase in availability on a MW for MW basis, and hence to a natural improvement in capacity margins. As a result, a smaller amount of capacity could replace a larger amount of capacity without any negative impact on the capacity margin.

For these two reasons, we think that it is much more reasonable to assume that only half of the fossil-fuel capacity that would be withdrawn on the assumption of a uniform operating life of 40 years will actually need to be replaced over this period to preserve the targeted capacity margin of 10%.

As a result, we conclude that a more realistic number for the total amount of new capacity required in Germany by 2012 would be 15-18GW, and by 2020 40-46GW (Figure 25).

Figure 25: Realistic estimate of new capacity required in Germany over 2010-20 (GW)

Motive for building new capacity	2012E	2012E-2020E	TOTAL BY 2020E
Amount required to re-establish a capacity margin of 10%	2.5	0.0	2.5
Annualised organic growth in peak-load demand (0.5%-1%)	3.0-6.1	3.6-7.5	6.6-13.6
Nuclear phase-out	6.2	14.1	20.3
Withdrawal of fossil-fuel plants after 40 years' operating life	3.3	6.7	10.0
TOTAL	15.0-18.1	24.4-28.3	39.4-46.4

Source: Deutsche Bank

So what are the current plans for new build in Germany?

... which means fossil-fuels should increase their market share dramatically

Figure 26 sets out the new-entrant power projects currently in various stages of planning in Germany, as based on a report by the German power-generation association (VDEW) and cited in a Reuters newswire report of 14 September 2006. According to this report, a total 22GW are planned by 2012, of which 7,700MW of gas, 3,600MW of lignite, and 10,700MW of coal.

The two key questions this list of new projects raises are (i) how much of this capacity is actually needed?; and (ii) now that the 4+14/4+10 rules have been rejected by the Commission how many of these projects are actually likely to go ahead?

Our calculations above lead us to assume that 15GW-18GW of new plant would actually be required by 2012, so the 22GW of potential new projects in Figure 26 already looks on the high side to us. This probably reflects the fact that until the Commission's ruling on Germany's Phase-2 NAP at the end of last November, there was an obvious incentive under the 4+14/4+10 rules to commission new lignite and coal plants to replace older, less efficient ones. In other words, there was an incentive to bring forward the withdrawal date of older lignite and coal plants even before they had reached their standard 40 years' operating life.

This means that even if all of this plant were to have been built, it would not necessarily have lead to overcapacity relative to our assumed requirement of 15GW-18GW, as it probably would have meant that more of the older plant would have closed sooner.

Figure 26: Planned new capacity in Germany (MW)

Location	Developer	Fuel	Capacity	Expected start-up
Weisweiler	RWE	Gas	540	2006
Lubmin I	Concord Power	Gas	1200	2008
Hamm-Uentrop	Trianel Power	Gas	800	2007
Herdecke	Mark-E/Statkraft	Gas	400	2007
Hürth	Statkraft	Gas	800	2007
Irsching 5	E.ON	Gas	800	2008
Lingen	RWE	Gas	850	2009
Brunswick	Brunswick Utility	Gas	400	2008
Bocholt	Advanced Power/Siemens	Gas	400	2009
North Hesse State	Iberdrola	Gas	1000	2010
Irsching 4	E.ON	Gas	530	2011
Neurath BoA II and III	RWE	Lignite	2100	2010
Boxberg	Vattenfall	Lignite	675	2011
Berlin	Vattenfall	Lignite	800	2012
Lünen	Trianel Power	Hard coal	750	2012
Duisberg-Walsum	Steag/EVN	Hard coal	750	2010
Lünen	Steag	Hard coal	750	2012
Hamburg-Moorburg	Vattenfall	Hard coal	1640	2011/12
North Germany	Electrabel	Hard coal	800	2010/11
Datteln	E.ON	Hard coal	1000	2011
Bremen-Mittelbueren	Stadtwerke Bremen	Hard coal	800	2011
Ruhr Region	EWMR (Bochum)	Hard coal	1100	2011
Herne 5	Steag	Hard coal	750	2011
Hamm-Uentrop	RWE	Hard coal	1600	2012
Mainz	KMW Mainz Wiesbaden	Hard coal	800	2011
TOTAL			22,035	

Source: VDEW, Reuters

However, we now think that much of this plant will not get built in any case because the incentive provided by the 4+14/4+10 rules has now been removed by the European Commission.

As explained in Section 1 above, without the guarantee of free carbon allowances for the next 18/14 years it is hard to see how any conventional lignite plants can be built by rational investors today given the likelihood of ever tighter carbon caps in future. Indeed, as we argued above, even coal looks risky if the carbon price is Euro 15/tonne or higher in future. By contrast, gas now looks all the more attractive in the wake of the Commission's ruling.

As a result, we assume that none of the planned lignite plants in Figure 26 will now go ahead, and that the amount of coal plant that gets built will be a function of the total requirement and the amount of diversity that generators feel it is desirable to have in their portfolios (as explained above in Section 1, generators will likely want to retain some diversity in order to hedge against potential changes in future commodity prices that could be more favourable to coal than gas).

By contrast, we would expect all of the 7,700MW of gas plant listed in Figure 26 to be built, plus however much were required on top of this in order to meet the total requirement after taking into account the amount of new coal plant that is likely to be built.

On this basis, we think it is reasonable to assume the scenarios for new build out to 2012 and 2020 set out in Figure 27 below.

Here we take the mid-range of our calculations for new-build requirements by 2012 and 2020E as set out in Figure 25 above, which gives a total new-capacity requirement of 16.5GW by 2012, and 42.4GW by 2020. We assume that investors will want coal to account for 25% of the total portfolio of new plant, and that renewables account for 10%. Overall, this would lead to new gas and coal build of 28GW and 11GW respectively by 2020.

Figure 27: Scenario for new build over 2010E-20E on DB assumptions (GW)

Fuel source of new capacity	New capacity built by 2012E (GW)	New capacity built by 2020E (GW)
Gas	10.8	27.6
Coal	4.2	10.6
Renewables	1.6	4.2
TOTAL NEW CAPACITY	16.5	42.4

Source: Deutsche Bank

The problem with this scenario, of course, is that it would be contrary to the German Government's two key energy-policy objectives, as it would lead to significantly higher carbon emissions and greater dependence on foreign energy supplies by 2020.

Phasing out nuclear would make the CO2 cuts aspired to impossible

Figure 28 sets out the carbon intensity of the different fuels used in power generation assuming BAT techniques. As can be seen, gas is clearly the cleanest of the fossil fuels, but nonetheless produces 0.37 tonnes of CO2 for every MWh of electricity generated, compared with zero emissions from a nuclear plant.

Figure 28: CO2 emissions from power generation by fuel type

Fuel source	Tonnes of CO2 emissions/MWh
Lignite	0.93
Coal	0.75
Gas	0.37
Geothermal	0.08
Biomass	0.02
Hydro	0.01
Nuclear	0.01
Wind	0.01

Source: IEA, EDF, RWE

This means that assuming the profile for new build set out in Figure 27 above and that the carbon intensity of the old, less efficient fossil-fuel plant being replaced is 1.15, then other things being equal carbon emissions from power generation would increase dramatically by 2020 compared with 2010.

Figure 29: Projected CO2 emissions from new power plants in Germany by 2020 on DB assumptions

New capacity by 2020E	Assumed new capacity (GW)	Assumed out put (TWh)	Assumed incremental CO2 emissions (m/T)
Gas to replace lost nuclear	19GW	146	53.3
Gas and renewables to keep capacity margins at 10% with 0.75% growth in peak-load demand	8.4GW of gas, and 4.2GW of renewables	94	21.8
Coal and gas to replace old fossil-fuel plant	10.6GW of coal, and 0.2GW of gas	80	-32.0
TOTAL NEW CAPACITY	42.4	320	43.1

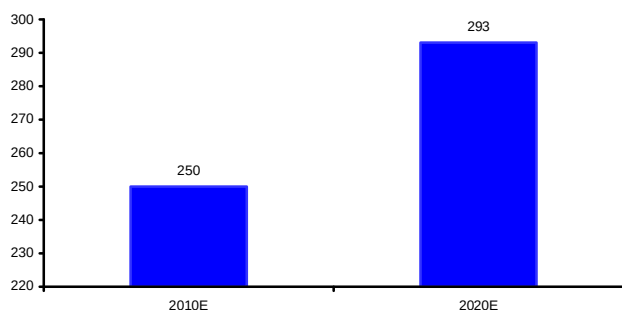
Source: Deutsche Bank

As Figure 29 shows, this is because of the 42.4GW of new build we here assume would be required by 2020, 19GW would be to replace the nuclear plant that would be withdrawn by then (we assume the final 1.3GW of nuclear capacity is withdrawn in 2022). A further 12.6GW would be required to keep capacity margins at a minimum 10% while allowing for annualized growth in peak-load demand of 0.75%. This would mean that only 10.8GW of this 42.4GW of new build would be replacing old, less efficient fossil-fuel plant.

As Figure 30 shows, the profile of emissions from the power sector in this case would be very different from the one policymakers implicitly aspire to by 2020 as shown in Figure 13 above. Instead of declining by 60m tonnes over 2010-2020 to 190m tonnes from 250m tonnes, emissions would actually increase by about 43m tonnes to 293m tonnes (in line with the incremental emissions shown in Figure 29).

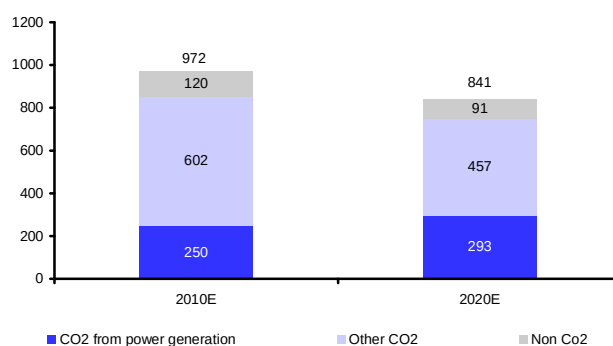
As a result, even assuming that all other sectors of the economy achieved reductions in line with the declared aspiration, emissions from power generation would mean that emissions overall by 2020 were 841m tonnes instead of the 738m tonnes aspired to. This would amount to a reduction of 31% rather than the 40% reduction aspired to by the German Government (Figure 31).

Figure 30: Estimated CO2 emissions for power generation, 2010-20, assuming nuclear phase-out and equal burden-sharing (m/T CO2)



Source: Deutsche Bank estimates

Figure 31: Estimated GHG emissions, 2010-20, assuming nuclear phase-out and equal burden-sharing (m/T CO2e)



Source: Deutsche Bank estimates

In short, we think that phasing out nuclear power would be absolutely incompatible with the German Government's policy aspiration to reduce total emissions by 40% against 1990 levels by 2020.

Moreover, given that the potential emissions reductions achievable in the power-generation sector are greater than those of any other sector if the right investments are made, we think that Figure 31 is probably too optimistic even on a best-case emissions scenario for the other sectors of the economy.

Figure 32: Burden-sharing for emissions reductions over 2010E-20E assuming same relative burden over 1990-2010E

Sector and GHG	Assumed reductions in emissions 1990-2010E (m/T CO2e)	% reduction against 1990 level	Reductions in emissions 2010E-2020E assuming same relative reduction as over 1990-2010E (m/T CO2e)
Power generation, CO2 reductions	-100	-29	-91
Other sectors of economy, CO2 reductions	-79	-17	-71
Economy overall, other GHG reductions	-80	-40	-72
TOTALGHG REDUCTIONS	-258	-21	-234

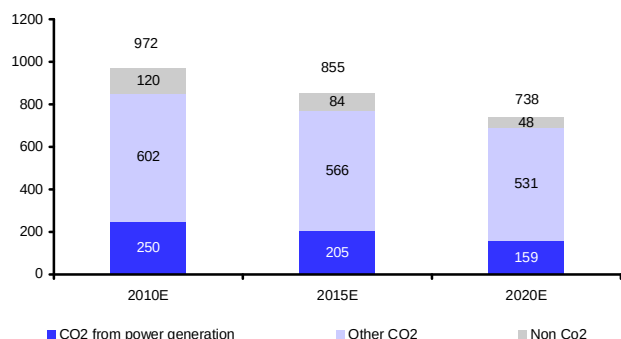
Source: Deutsche Bank

In other words, we think that in order to achieve emissions reductions of 40% against 1990 levels, Germany would again have to put a disproportionately large share of the burden on the power sector, just as it is doing in order to meet its Kyoto targets. Figure 32 shows how the required reduction between 2010 and 2020 would break down assuming the same relative burdens on each sector over this period as over 1990-2010.

Of the 234m tonnes of reductions necessary between 2010 and 2020 to achieve the 40% cut against 1990 levels aspired to, this would imply a 91m tonne cut in the emissions of the power-generation sector, rather than the 60m tonnes power stations would need to cut if they were sharing the burden equally with other sectors of the economy.

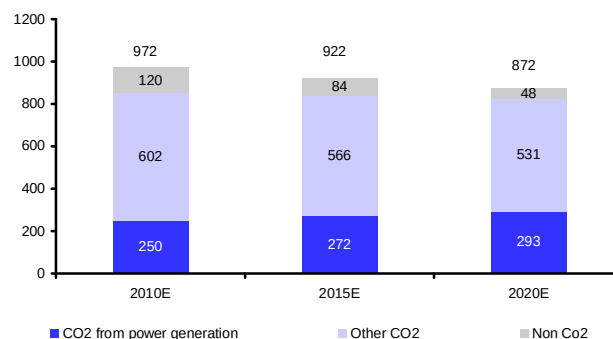
Figure 33 shows the how the trajectory for achieving the policy aspiration of a 40% cut by 2020 would look assuming the same burden-sharing as over 1990-2010, and Figure 34 our estimate of the out-turn given that we think the nuclear phase-out would lead to an increase in emissions from the power sector of 43m tonnes by 2020.

Figure 33: Trajectory for a 40% cut in emissions by 2020 assuming same burden-sharing from 2010 as over 1990-2010E (m/T CO₂e)



Source: Deutsche Bank estimates

Figure 34: Estimated realistic out-turn of emissions in 2020 assuming nuclear phase-out takes place (m/T CO₂e)



Source: Deutsche Bank estimates

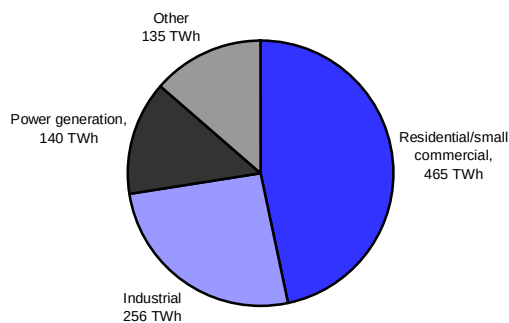
In short, if nuclear power is phased out in Germany and we assume the same relative burden-sharing over 2010-2020 as over 1990-2010, then we estimate that total emissions – always assuming the other sectors were in practice able to achieve their targets -- would fall by only 29% by 2020 against 1990 levels, rather than by the 40% aspired to by the German Government.

Phasing out nuclear would greatly increase dependence on imported gas

In 2005, Germany's total gas demand was 996TWh (Figure 35), with residential and small commercial customers accounting for nearly half of this (465TWh), and industrial customers for 26% (256TWh). Gas for use in power generation accounted for only 14%, at 140TWh.

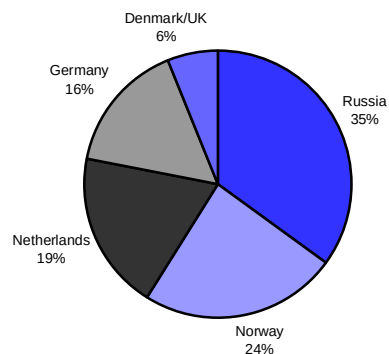
Meanwhile, the sourcing of Germany's gas shows that it is already very heavily dependent on foreign imports, with Russia accounting for 35% of requirements in 2005, Norway for 24%, and the Netherlands for 19%. Germany itself provided only 16% of its own needs, and with reserves running down this number is set to decline over time.

Figure 35: German gas-demand by end-user, 2005 (TWh)



Source: German Gas and Water Federation, German Government, RWE

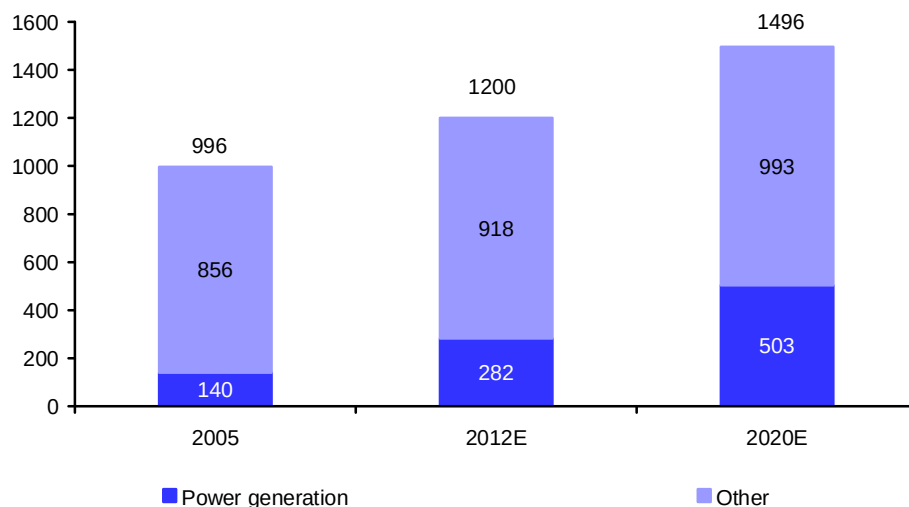
Figure 36: Sources of German gas, 2005 (%)



Source: German Gas and Water Federation, RWE

Taking our assumptions for new gas-fired power-generation capacity over 2010-2020 as outlined in Figure 29 above, we estimate that gas consumed by power plants in Germany will rise very sharply in both absolute and relative terms over the next decade.

Figure 37: Assumed increase in German gas demand with nuclear phase-out (TWh)



Source: VGB PowerTech e.V

In total, we assume 27.6GW of new gas plant will be required if the nuclear phase-out goes ahead as planned, and that this plant would be generating an extra 206TWh of electricity by 2020E compared with the amount of power generated from gas in 2005.

However, even assuming state-of-the-art efficiency rates in gas plants of 57%, this means that demand for gas from power generators would increase by 362TWh by 2020, to 503TWh from 146TWh in 2005. This would represent an increase of 260% on 2005 levels.

Moreover, if we assumed average annualised growth in gas demand over 2005-20 for the rest of the economy, then this would mean that total demand would increase by 50% by 2020 against 2005 levels: 363TWh for power plants, and 138TWh for the rest of the economy (Figure 37).

Clearly, an increase in demand on this scale would lead to an ever greater reliance on imported gas over time. Given that Russia and Norway are probably the best positioned of Germany's existing suppliers to increase their exports, this could mean that Russia might account for as much as 50% or more of Germany's gas needs by 2020E, or up to 750TWh compared with approximately 350TWh in 2005. In short, phasing out nuclear power would be clearly negative for Germany's security of supply.

Conclusion

Phasing out nuclear power stations long before the end of their technically feasible lifetimes reduces the length of the capital cycle and therefore increases the long-term power price unnecessarily.

In addition, though, this policy clashes directly with the German government's two main energy-policy objectives today: (i) reducing carbon emissions over time, and (ii) ensuring security of supply.

As a result, we think the only realistic way for Germany to balance the competing challenges its energy-policy faces is to extend the lifetime of its nuclear plants and to encourage clean-coal plants to be built with the proceeds of a windfall tax on these extensions.

3. Nuclear extensions and clean coal are the solution

We think the only way for Germany to achieve its dual policy objectives of reducing carbon emissions and ensuring security of supply is to extend the lifetime of existing nuclear plants and to subsidise new CCS plants with windfall taxes on these extensions.

On our calculations, extending the lifetime of all nuclear-power plants in Germany to 60 years could raise an extra Euro 800m per year initially for the Government (rising to Euro 2bn per year by 2022E), money which could then be used to incentivise clean-coal plants to be built.

On the assumption that new-entrant gas with carbon fully priced in requires a price of Euro 54/MWh and CCS plants a price of Euro 64/MWh, we calculate that setting aside the incremental taxes from nuclear extensions in competitive auctions for bidders keen to cover the price gap to new-entrant gas could encourage 1,400MW of clean-coal capacity per year by 2012E, or a total of 7,500MW within the first six years of such a policy being implemented.

We calculate that the two great advantages of such a policy are: (i) it would enable Germany to reduce its CO₂ emissions from power generation by 50% against 1990 levels by 2020, and hence allow this sector (once again) to achieve more than its fair share of the overall reduction in emissions the Government is targeting by 2020 (a 40% cut against 1990 levels); (ii) it would limit the rise in Germany's gas imports over 2005-2020 to 92TWh compared with the 362TWh increase over this period that would otherwise happen.

Life extensions to nuclear plants are technically possible ...

Of the 17 nuclear stations still operating in Germany, 11 are PWRs, and six BWRs. Most nuclear-power plants originally had a nominal design lifetime of up to 40 years, but engineering assessments over the last decade have established that many can operate longer.

In the US, for example, more than 44 reactors have been granted licence renewals extending their operating lives from 40 to 60 years. According to the World Energy Council (www.worldenergy.org), the first licence renewal in the world of a commercial nuclear-power plant was issued in the US in March 2000, with a 20-year extension of both units of the Calvert Cliffs PWR plant to 60 years from 40 years.

This was followed shortly afterwards by a 20-year extension to the three units of the Oconee PWR plant, and by the end of 2005, out of a total of 103 reactors in the US 39 had been granted 20-year licence extensions, and another 39 operators had applied for or had applications pending for life extensions.

Given the technical feasibility of extending the operating lives of Germany's nuclear stations, the main obstacle is political. However, wider energy-policy priorities have come to the fore since the nuclear-consensus law was agreed in 2000, and Germany must now find a realistic way of reducing carbon emissions and securing future energy requirements. We believe that nuclear extensions must form the bedrock of such a realistic policy.

... and would improve Germany's outlook for CO2 emissions and energy dependence against the phase-out scenario

Extending the lifetime of Germany's nuclear plants would have three advantages:

1. 19GW of plant that would otherwise have to be replaced by 2020 could continue operating and the investment that would otherwise have gone into replacing this plant would find alternative uses elsewhere in the economy.
2. Germany's emissions profile over 2010-20 would benefit greatly from such an extension. First, the 19GW of nuclear capacity that on our assumptions above would otherwise have been replaced with gas will continue to emit zero CO2.

Second, assuming the same relative breakdown of new plant build – 65% gas, 25% coal, 10% renewables -- this would mean that more of the new gas built would be replacing old fossil-fuel plant. This would mean that of the 23.4GW of plant that would be required by 2020E on this scenario, 15.3GW would be gas, 5.8GW coal, and 2.3GW renewables (Figure 38).

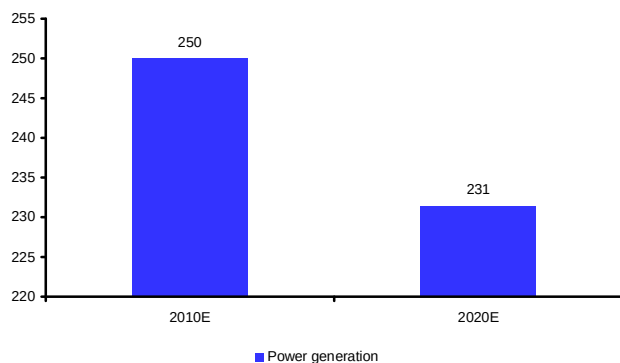
Figure 38: Projected CO2 emissions from new power plants in Germany by 2020E on DB assumptions

New capacity by 2020E	Assumed new capacity (GW)	Assumed out put (TWh)	Assumed incremental CO2 emissions (m/T)
Gas and renewables to keep capacity margins at 10% with 0.75% growth in peak-load demand	10.3GW of gas, and 2.3GW of renewables	94	27.4
Coal and gas to replace old fossil-fuel plant	5.0GW of gas, and 5.8GW of coal	80	-46.0
TOTAL NEW CAPACITY	23.4	174	-18.6

Source: Deutsche Bank

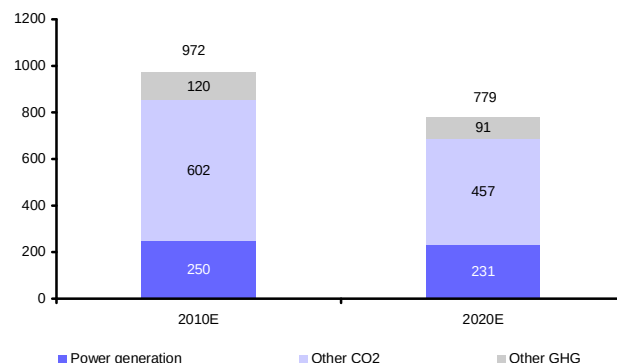
On our estimates, and again assuming an average carbon-intensity factor of 1.15 for the old fossil-fuel plant to be replaced, then this scenario would lead to a total reduction in emissions from power generation over 2010-20 of 19m tonnes, compared with an increase of 43m tonnes if nuclear were phased out (Figure 39).

Figure 39: Estimated CO2 emissions for power generation in Germany, 2010-20, assuming nuclear extensions but no CCS (m/T CO2e)



Source: Deutsche Bank

Figure 40: Estimated out-turn of emissions in Germany by 2020 assuming nuclear extensions but no CCS (m/T CO2e)



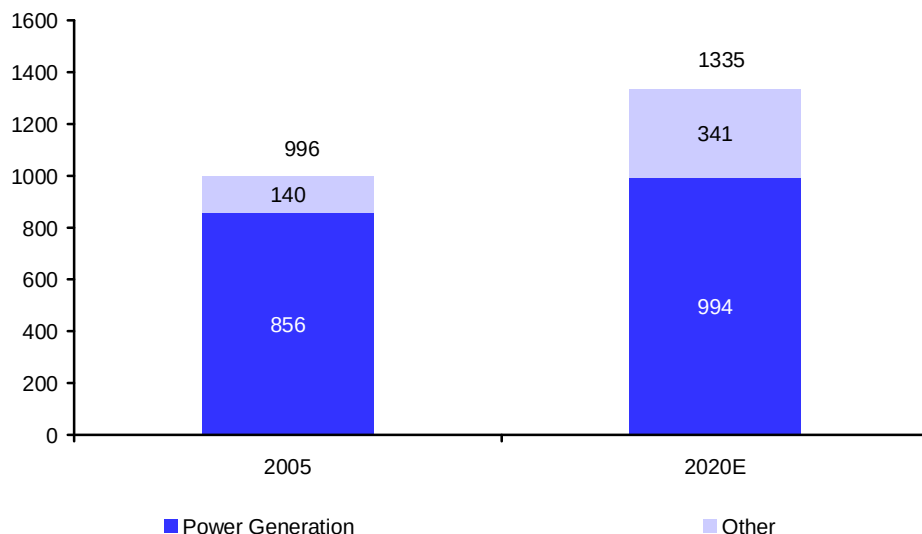
Source: Deutsche Bank

Assuming that the burden for reducing emissions over 2010-20 were shared proportionately between the different sectors of the economy, and that the other sectors of the economy achieved their targeted reductions, this would mean that total GHG emissions would fall to 779m tonnes of CO2e by 2020. This would be 37% below the 1990 level of 1,230m tonnes, and close to the 738m tonnes that would correspond to the 40% reduction aspired to (Figure 40).

3. The increase in Germany's dependence on imported gas over 2010E-20E would be much less pronounced.

With 15.3GW of gas to be built on this scenario, rather than the 27.6GW we assumed would be needed in the event of the nuclear phase-out going ahead, then the increased demand for gas to be used in power stations over 2005-2020E would be 199TWh, rather than the 362TWh we assumed above under the nuclear-phase-out scenario (Figure 41).

Figure 41: Assumed increase in German gas demand with nuclear extensions but no CCS (TWh)



Source: Deutsche Bank

However, a more radical policy could lead to much more significant benefits on emissions and security of supply than this. If Germany were to extend the lifetime of its nuclear plants to 60 years and put a windfall tax on all nuclear-generated output, then it could help finance a first generation of clean-coal plants that would make Germany a global leader in CCS technology.

... but if combined with support for clean coal the outlook for emissions and security of supply would be even brighter

Figure 42 sets out our estimates of how much incremental revenue would be raised for the German Government annually if it were to extend the lifetime of its nuclear plants to 60 years and tax all nuclear output going forward at a rate of 50% (rather than the standard current rate of 30%).

In other words, our assumption is that the German Government receives an extra 20% in tax revenues from each power station up until its 32nd year compared with what it would have received under the phase-out scenario, and that thereafter it receives an extra 50% compared with what it would have received. We assume our new long-term power-price of Euro 50/MWh, and that nuclear output has cash costs of Euro 25/MWh, giving a taxable margin of Euro 25/MWh.

On the basis of these assumptions, we calculate that the Government would receive incremental tax revenue of Euro 780m in 2007, rising to Euro 1.95bn by 2022, the date by which under current legislation the last plant scheduled to be closed would be withdrawn.

Figure 42: Potential incremental tax revenues for the German Government from nuclear extensions (Euro m)

PLANTS STILL OPERATING	Expected closure date	Capacity (MW)	Annual output	Assumed incremental tax revenue up to 32 nd years	Assumed incremental tax revenue after 32 nd years	INCREMENTAL TAX PER YEAR	
						Year	Assumed incremental tax revenue (Euro m)
Biblis A*	2008E	1,167	7	35	88	2007E	780
Neckarwestheim 1	2009E	785	6	30	75	2008E	833
Biblis B**	2009E	771	9	45	113	2009E	945
Brunsbüttel	2010E	1,240	4	20	50	2010E	975
Isar 1	2011E	878	7	35	88	2011E	1,028
Unterweser	2012E	1,345	9	45	113	2012E	1,095
Philippsburg 1	2013E	890	6	30	75	2013E	1,140
Grafenrheinfeld	2014E	1,275	10	50	125	2014E	1,215
Grundremmingen B	2015E	1,284	10	50	125	2015E	1,290
Grundremmingen C	2016E	1,392	11	55	138	2016E	1,373
Krümmel	2017E	1,284	11	55	138	2017E	1,455
Philippsburg 2	2018E	1,288	11	55	138	2018E	1,620
Grohnde	2018E	1,360	11	55	138	2019E	1,703
Brokdorf	2019E	1,370	11	55	138	2020E	1,868
Elsland, Lingen	2020E	1,329	11	55	138	2021E	1,868
Isar 2	2020E	1,400	11	55	138	2022E	1,950
Neckarwestheim 2	2022E	1,269	11	55	138		
TOTAL		22,641	156	780	1,950		

Source: German Government, Deutsche Bank estimates. *Given the ongoing outage from Q4 of 2006, Biblis A may now close in 2009E; **With transferred output from Mühlheim-Kärlich, Biblis B will in practice probably not shut until 2011E.

The point is that the Government could then set aside the taxes raised from this policy to subsidise the building of clean-coal plants. The question is, what is the cost of clean coal -- that is coal plant with carbon-capture and storage (CCS) capabilities -- and hence of zero or close-to-zero emissions?

More specifically, how does the cost of a CCS plant compare with the cost of a new gas plant (the new-entrant fuel of choice)? After all, it is the answer to this question that will determine the size of the subsidy required to incentivise new CCS build, and hence the amount of capacity that could reasonably be expected to develop as a result of a tax on nuclear output.

Fuel costs are the key variable in the cost of a new gas plant ...

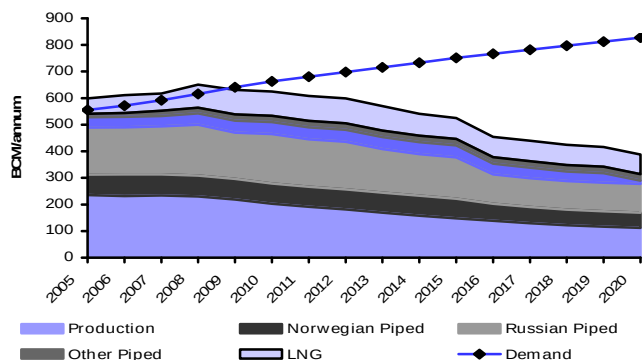
Above we outlined our estimate of the cost of a new gas plant at Euro 54/MWh (Figure 4), and explained that the key factor in the economics of a new gas plant was the cost of the gas itself (Figure 5). On our calculations, assuming thermal equivalency and the DB long-term oil-price forecast of \$44/boe, fuel costs would account for 62% of the total costs. We think basing gas-price expectations of thermal equivalency is the rational thing for new entrants to do, despite the traditional indexing of gas to oil on other criteria.

We expect indigenous European production to fall from 2010 and expect Europe will become increasingly dependent on LNG and Russian gas post 2010 (Figure 43). While action is being taken already to secure future supplies (such as the Baltic Pipeline, which should add 27.5BCM of capacity from 2010), the potential uncertainty surrounding reliance on LNG and Russian gas should prove positive for pricing.

Figure 44 displays the implied forward gas price, at various oil prices, using Troll and thermal equivalency. Thermal equivalency is an energy-based relationship between oil and gas that assumes the cost of the two fuels should converge on the basis of the amount of energy

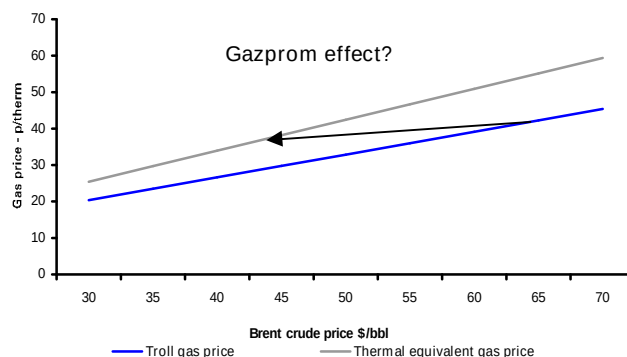
produced by each fuel (a barrel of oil contains the same amount of energy as 60 therms of gas). As Europe becomes more dependent on Russian gas we believe that Gazprom is likely to have more influence on European gas pricing.

Figure 43: European gas supply / demand outlook



Source: Deutsche Bank

Figure 44: Troll versus thermal equivalency



Source: Deutsche Bank

While we believe that Gazprom may be comfortable setting gas prices below the implied thermal equivalent level at high oil prices, a fall in oil prices (we assume Brent Crude will fall to \$44/bbl by 2010) could very well lead to pressure from Gazprom to move above Troll and price closer to thermal-equivalent pricing. Indeed, in our view Russia's more aggressive renegotiation of oil and gas contracts with a number of eastern European countries in recent months would suggest that rational investors should assume that this is what will happen.

So, how does the cost of a CCS plant compare with Euro 54/MWh for gas?

... but the costs of a CCS plant are still uncertain

Figure 46 sets out our assumptions for a new clean-coal plant using CCS technology. The big difference between estimating the cost of a CCS plant and a new gas plant is that nobody has yet built a CCS plant, so some of the crucial elements in the cost equation are much more speculative. In particular, the capital costs and fixed operating costs are more difficult to estimate because by definition these will not be known for sure until plants of this kind designed for full commercial operation have actually been built.

This is very significant, because as we saw above (Figure 7), capital costs are key in the construction of a conventional coal plant, accounting for 30% of the total. Despite the more speculative nature of our estimates for the cost of a CCS plant, we do nonetheless have some concrete estimates to go on, as RWE announced last year that it plans to build the first such plant in the world in Germany.

RWE said the total investment for the 450MW plant would be "approximately Euro 1bn", and that if everything were to run smoothly it could come on line by 2014E. At the same time, the UK Government recently published a very large document on alternative energy scenarios, with numerous sensitivities on the economics of different fuel sources for use in power generation. Concerning clean-coal technology, the report looked at the cost of Integrated-Gasification Clean Coal with CCS (the same technology being used by RWE in its clean-coal plant), and estimated the range for capital costs at Euro 2,179/MW-Euro 2,573/MW (Figure 45). It also gave estimates for fixed and variable operating costs, and for efficiency.

Figure 45: Estimates for the costs of a clean-coal power plant

	Capital cost (Euro/MW)	Fixed operating costs (Euro/kw)	Variable operating costs (Euro cents/kw)	Efficiency rate (%)
IGCC with CCS (low case)	2,178m	39	0.4	39
IGCC with CCS (low case)	2,573m	150	0.6	39

Source: UK Government

On the basis of these sources, we have modelled the power price required for an IGCC plant with CCS on the basis of the variables set out in Figure 46. We would note that we understand such a plant could work equally efficiently using lignite as hard coal.

Figure 46: Key assumptions for a clean coal/lignite plant with CCS

Variable	Assumption
Capital cost	Euro 2,222 /MW
Capacity	800MW
Capital outlay	Euro 1.777m
Required return (pre-tax real)	9.6%
Coal price	\$60/tonne
Coal price	Euro 1.78/GJ
Efficiency rate	35%
Coal price	Euro 18.3/MWh
Fixed operating costs	Euro 60/kw
Variable operating costs	Euro 3/MWh
Carbon intensity	0.0
Load factor	86%
Power price necessary to earn required return	Euro 63.8MWh

Source: Deutsche Bank

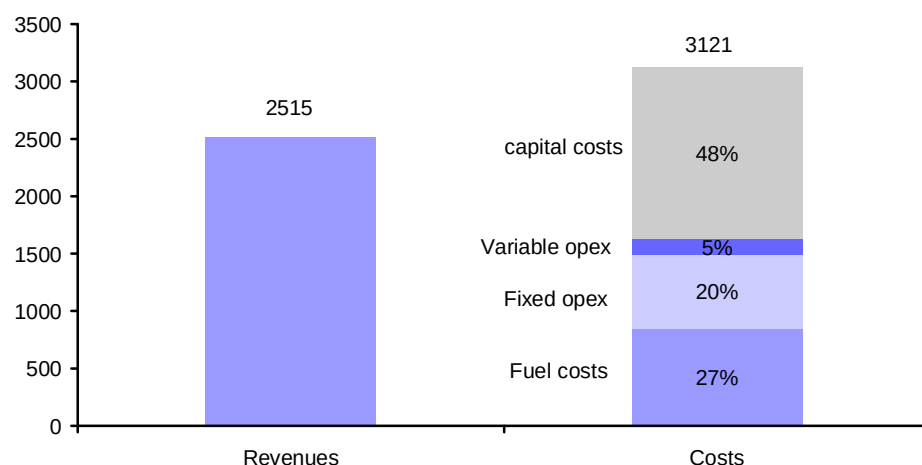
On the basis of all these assumptions, we calculate that a new clean-coal plant would earn its required rate of return with a power price of Euro 63.8/MWh. Interestingly, on our calculations this would be the same price required by a new lignite plant assuming carbon fully priced in at Euro 30/tonne as opposed to Euro 25/tonne.

With its long lead time we do not think any clean-coal plants commissioned today would come on line before 2013, so we think the correct cost comparison is against gas assuming that gas has to pay for 100% of its carbon allowances. This is because we assume full auctioning for new entrants in the ETS from 2013.

If a new gas-plant paying for 100% of its carbon allowances could earn its return at Euro 54.3/MWh, then rational investors would build gas, and an IGCC plant with CCS built under these assumptions would then receive the new-entrant gas price of Euro 54.3/MWh.

Figure 47 sets out the total costs against revenues for an 800MW clean-coal plant assuming it receives the new-entrant gas price of Euro 54.3/MWh. For such a plant, capital costs are by far the most important component, accounting for 48% of the total. Fuel and fixed operating costs are the next most important at 27% and 20% of the total respectively, but variable costs would be negligible.

As can be seen, under this scenario, an 800MW clean coal plant would not earn its required return, but rather would destroy just over Euro 606m of value, or approximately 34% of the capital invested.

Figure 47: Breakdown of costs for an 800MW clean-coal plant (Euro m)

Source: Deutsche Bank

In short, with a gap of 10/MWh against the price required by new gas, clean-coal plants would require subsidies from the German Government to be competitive, and we estimate that the size of this subsidy would be Euro 758/kw.

We estimate that taxes on nuclear extensions could fund up to 7,500MW of clean-coal capacity within six years

Figure 48 sets out our estimates of how much clean-coal capacity could be incentivised if the incremental taxes from nuclear extensions we assumed in Figure 39 above were used to plug the price gap of Euro 10/MWh between gas and clean coal. In the first year, the Euro 758m of incremental tax raised could fund 1,100MW of capacity (i.e. 780/758), but this figure would rise to 1,445MW by 2012 in line with a higher incremental tax take.

Figure 48: Potential amount of clean-coal capacity that could be subsidised, over 2007-12 (Euro m)

Year	Assumed incremental tax revenue (Euro m)	Assumed subsidy required per 1,000MW (Euro m)	Amount of capacity that could be incentivised (MW)
2007E	780	758	1,030
2008E	833	758	1,100
2009E	945	758	1,247
2010E	975	758	1,287
2011E	1,028	758	1,357
2012E	1,095	758	1,445

Source: German Government, Deutsche Bank estimates

As Figure 49 shows, this means that by 2012 a total of 7.5GW would be potentially financeable with such subsidies, and by 2020 23GW.

Clearly, this is a hypothetical number insofar as it depends on assumptions that have not yet been proven in practice, and given that the lead-time between commissioning and operation is a long one (six or seven years on RWE's estimates).

Figure 49: Potential total clean-coal capacity that could be subsidized out of taxes on nuclear extensions by 2012E and 2020E (MW)

Year	Assumed accumulated tax revenue (Euro m)	Implied accumulated new capacity that could be funded
2012E	5,709	7,466
2020E	17,373	22,850

Source: German Government, Deutsche Bank estimates

However, even after allowing for the speculative element inherent in these numbers, we think the benefits that would accrue from such a policy in terms of reducing emissions and slowing down the rate of increase in energy imports are so great that they are bound to be taken seriously by policymakers.

Clean coal would greatly reduce emissions and would not increase dependence on imported gas

Extending the lifetime of Germany's nuclear plants and using the incremental tax take would have three major benefits, but the second two would be much more pronounced than was the case in the scenario we looked at earlier in this section:

1. 19GW of plant that would otherwise have to be replaced by 2020 could continue operating and the investment that would otherwise have gone into replacing this plant would find alternative uses elsewhere in the economy.
2. Germany's emissions profile over 2010-20 would benefit greatly from such an extension. First, the 19GW of nuclear capacity that on our assumptions above would otherwise have been replaced with gas will continue to emit zero CO₂.

Second, assuming that the breakdown of new build were much more weighted in favour of clean coal than of gas – 60% clean coal, 30% gas, 10% renewables -- this would mean that the majority of old fossil-fuel fired plant to be withdrawn over 2010-20 would be replaced by zero-emissions plant. This would mean that of the 23.4GW of plant that would be required by 2020 on this scenario, 14GW would be clean coal, 7GW gas, and 2.3GW renewables (Figure 50).

Figure 50: Projected decrease in CO₂ emissions from new power plants by 2020E assuming 60% clean coal new build

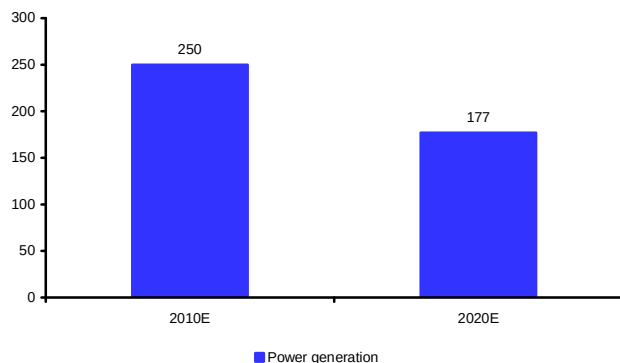
New capacity by 2020E	Assumed new capacity (GW)	Assumed out put (TWh)	Assumed incremental CO ₂ emissions (m/T)
Gas and renewables to keep capacity margins at 10% with 0.75% growth in peak-load demand	10.3GW of clean coal, and 2.3GW of renewables	94	0.0
Coal and gas to replace old fossil-fuel plant	3.8GW of clean coal, and 7GW of gas	80	-73.0
TOTAL NEW CAPACITY	23.4	174	-73.0

Source: Deutsche Bank

On our estimates, and again assuming an average carbon-intensity factor of 1.15 for the old fossil-fuel plant replaced, then this scenario would lead to a reduction in emissions from power generation over 2010-20 of 73m tonnes, against an increase of 43m tonnes if nuclear were phased out (Figure 51).

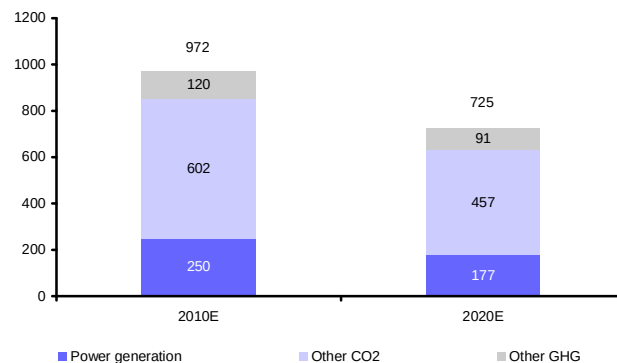
Assuming that the burden for reducing emissions over 2010-20 were shared proportionately between the different sectors of the economy, and that the other sectors of the economy achieved their targeted reductions, this would mean that total GHG emissions would fall to 725m tonnes of CO₂e by 2020. This would be 41% below the 1990 level of 1,230m tonnes, slightly lower than the 738m tonnes that would correspond to the 40% reduction aspired to (Figure 52).

Figure 51: Estimated CO₂ emissions for power generation in Germany, 2010-20, assuming nuclear extensions and CCS new build (m/T CO₂e)



Source: Deutsche Bank

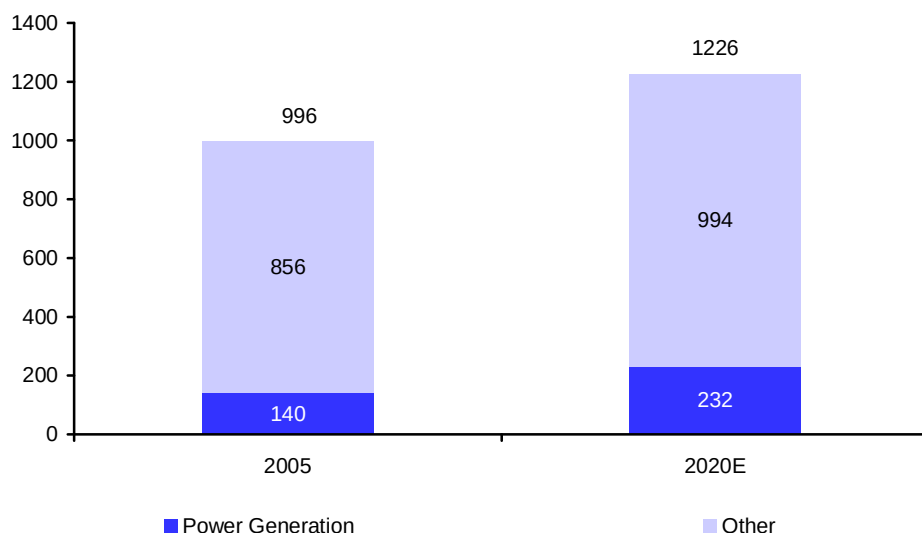
Figure 52: Estimated out-turn of emissions in Germany by 2020 assuming nuclear extensions and CCS new build (m/T CO₂e)



Source: Deutsche Bank

3. The increase in Germany's dependence on imported gas over 2010-20 would be much less pronounced. With only 7GW of gas to be built on this scenario, rather than the 27.6GW we assumed would be needed in the event of the nuclear phase-out going ahead, then the increased demand for gas to be used in power stations over 2005-2020 would be 92TWh, rather than the 362TWh we assumed above (Figure 53).

Figure 53: Assumed increase in German gas demand with nuclear extensions and CCS new build (TWh)



Source: Deutsche Bank

Conclusion

Extending the life of Germany's power stations to the maximum length technically possible while supporting the development of CCS technology is, in our view, the only realistic policy option open to the German Government if it really wants significantly to reduce carbon emissions over time while also ensuring security of supply.

4. Valuation implications

For both E.ON and RWE, German power generation is the most important single component in our sum-of-the-parts (SotP) valuations, accounting for 23% of our previous enterprise valuation of E.ON (Euro 24bn out of Euro 106bn), and 30% of our previous enterprise valuation of RWE (Euro 23bn out of Euro 74bn).

Taking our new long-term power price forecast of Euro 50/MWh and other adjustments we have made to carbon, coal, and lignite prices adds 3.8/share to our valuation of E.ON and Euro 7.7/share to our valuation of RWE. Assuming an extension of the nuclear plants operating lives to 60 years and a 50% tax rate on nuclear output adds a further Euro 3.4/share to E.ON's valuation, and Euro 2.2/share to that of RWE.

The main risks to the changes we have made to our valuations are that gas and carbon prices are lower in future than we are now assuming, and/or that the European carbon-trading scheme breaks down in future, thereby making coal and conventional lignite new build the new entrant of choice and therefore reducing our long-term power-price forecast.

Our new long-term power price assumption is Euro 50/MWh

Figure 54 sets out our assumptions for new gas and coal plants under two scenarios: (i) assuming the new entrant has to pay for 100% of its carbon allowances at Euro 25/tonne; (ii) assuming free carbon allowances for the first five years, but that thereafter it has to pay for all of its allowances (this is effectively the situation in Germany over 2008-12).

Figure 54: Power price required by a new gas plant with and without carbon costs				
Variable	Gas with carbon fully priced in	Gas with free carbon for first 5 years	Coal with carbon fully priced in	Coal with free carbon for first 5 years
Capital cost	Euro 563,000/MW	Euro 563,000/MW	Euro 1,313,000/MW	Euro 1,313,000/MW
Capacity	1,000MW	1,000MW	1,000MW	1,000MW
Capital outlay	Euro 563m	Euro 563m	Euro 1,313m	Euro 1,313m
Required return (pre-tax real)	9.6%	9.6%	9.6%	9.6%
Oil price	\$44/boe	\$44/boe	n/a	n/a
Gas price / Coal price	Euro 5.35/GJ	Euro 5.35/GJ	Euro 1.78/GJ	Euro 1.78/GJ
Efficiency rate	57%	57%	47%	47%
Gas price / Coal price	Euro 33.8/MWh	Euro 33.8/MWh	Euro 13.6/MWh	Euro 13.6/MWh
Fixed operating costs	Euro 12/kw	Euro 12/kw	Euro 45/kw	Euro 45/kw
Variable operating costs	Euro 2.25/MWh	Euro 2.25/MWh	Euro 2.25/MWh	Euro 2.25/MWh
Carbon price	Euro 25/tonne	Carbon permits allocated for free for first five years, thereafter Euro 25/tonne	Euro 25/tonne	Carbon permits allocated for free for first five years, thereafter Euro 25/tonne
Carbon intensity	0.365	0.365	0.75	0.75
Load factor for first 18 years	86%	86%	86%	86%
Annual output for first 18 years	7.5TWh	7.5TWh	7.5TWh	7.5TWh
Load factor for remaining 22 years	40%	40%	40%	40%
Annual output for remaining 22 years	3.5TWh	3.5TWh	3.5TWh	3.5TWh
Power price necessary to earn required return	Euro 54.3/MWh	Euro 50.5/MWh	Euro 58.5/MWh	Euro 50.8/MWh

Source: Deutsche Bank

With all the other variables the same for both plants, the power price required by the gas plant that has to pay for all its carbon requirements is Euro 54.3/MWh, and for coal Euro 58.5/MWh. By contrast, gas and coal are very close if they both receive free carbon for the first five years but thereafter have to pay for all their allowances. Under this scenario, the new-entrant price for gas is Euro 50.5/MWh, while for coal it would appear to be Euro 50.8/MWh.

In practice, the situation today is that new entrants will receive all of their carbon for free over 2008-12, but on a worst-case basis could face full auctioning from 2013 onwards. This is because when the next-but-one ETS trading period starts in 2013 any plants that start operating over 2008-12 will no longer be considered as new entrants but as incumbents.

Incumbents already receive fewer permits than they need relative to their business-as-usual requirements. The German Government originally proposed a ratio of 85% against BAU needs for incumbents over 2008-12, but the Commission's cuts to the German NAP mean that this figure will probably end up being lower than this, and incumbents can expect to see their allocations cut further from 2013.

In addition, however, it is quite possible that they will have to pay for the lower number of permits available to them from 2013, rather than receiving their allocations for free as is the case at the moment.

As a result, we think a rational investor building a new plant in Germany today would assume the most conservative scenario from 2013 onwards (i.e. that 100% of its carbon requirements have to be purchased at the market price), and this would give a new-entrant price of Euro 50.5/MWh assuming a carbon price of Euro 25/tonne. To derive our new-entrant power price we round this figure down to [Euro 50/MWh](#).

As we explained above in Section 1, we think that gas will be the predominant new entrant of choice in a carbon-constrained world where new plants have to pay for all their permits, but we also think this will be the case even over 2008-12, despite the fact that the five years' worth of free carbon initially would appear to make coal competitive with gas. This is because coal will not be as competitive as the small price differential – Euro 50.8/MWh versus Euro 50.5/MWh for gas – in Figure 54 implies:

1. Although a new coal plant will not have to buy any permits in the first five years, if the carbon price were at any point to go above Euro 25/tonne over 2008-12 it would not be able to run at its maximum load factor. At that point it would have to sell permits rather than generate, and it would therefore be making less money than the new gas plant. This is because the gas plant would still be generating and would therefore be capturing both the value of the free permits in the power price, and a margin on the power generated.

In other words, even though a coal plant might look competitive to *build* against gas assuming an equilibrium carbon price of Euro 25/tonne for the duration of the plant's lifetime, in reality it would not be competitive to *run* against gas whenever the carbon price rose above this level.

2. The new coal plant would be more vulnerable to future increases in carbon prices beyond the first five years, such that if the carbon price were higher than Euro 25/tonne in subsequent trading periods it would require a noticeably higher price than gas to meet its required return. On our calculations, if the price were Euro 25/tonne over 2008-12, but then Euro 30/tonne after 2013 a new coal plant would require a price of Euro 53/MWh, while a new gas plant would be economic at Euro 51.6/MWh.

Again, though, the caveat just mentioned under point (i) would apply: under these circumstances any coal plant built would not be able to run baseload, so in reality the price required would be even higher than Euro 53/MWh, and rational investors would therefore simply not build coal.

Finally, it is worth noting that that new entrants will be treated differently in future ETS periods from how they will be treated over 2008-12. New entrants that start operating for the first time from 2013 may have to pay for 100% of their carbon requirements from the beginning, and at the very least are unlikely, in our view, to receive 100% of their initial requirements (i.e. over the first five years) for free. Other things being equal, this means that we would expect the new-entrant price to rise over time, and for gas to be the even more predominant new-entrant fuel of choice after 2013.

We now assume a 60-year operating life for the nuclear plants

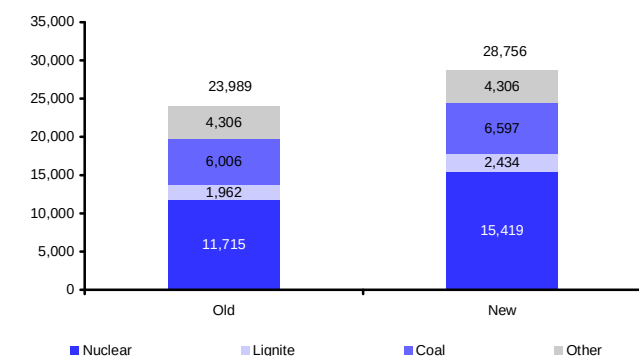
We are now assuming a 100% likelihood of an extension of Germany's nuclear power plants' lives to 60 years, and a 50% tax rate on all nuclear output going forward. This compares with our previous assumptions of a 50% likelihood of an extension of these plants' lives to 52 years, and a 35% tax rate on nuclear output.

The impact on our valuations of E.ON and RWE

Figures 55 and 56 set out our valuations of E.ON's and RWE's German generation businesses by comparing our new assumption for long-term power prices of Euro 50/MWh against our previous assumption of Euro 45/MWh, and taking into account our revised assumptions on nuclear extensions.

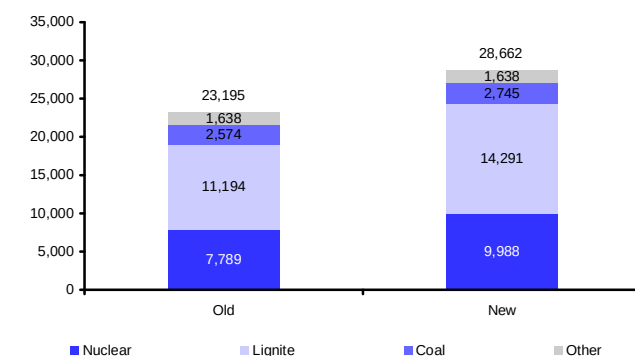
Regarding commodity prices for existing power plants, our assumptions are now in line with those used in our new-entrant models set out in Section 1 above. We have raised our carbon-price forecast from 2013 onwards to Euro 25/tonne (Euro 15/tonne previously), although we continue to assume that incumbent plants will receive 50% of their allocations for free. For coal and lignite prices we are now assuming Euro 1.78/GJ and Euro 0.7/GJ respectively.

Figure 55: Change in the EV of E.ON's German power business based on new assumptions (Euro bn)



Source: Deutsche Bank

Figure 56: Change in the EV of RWE's German power business based on new assumptions (Euro bn)



Source: Deutsche Bank

Figure 57: E.ON increase in value of power plants on new assumptions (Euro m)

Fuel type	Previous valuation (Euro m)	New valuation (Euro m)	Difference (Euro m)	Difference per share
Nuclear	11,715	15,419	3,7044	5.6
Lignite	1,962	2,434	472	0.7
Coal	6,006	6,597	591	0.9
Other	4,306	4,306	0	0.0
TOTAL	23,989	28,756	4,767	7.2

Source: Deutsche Bank

On the basis of our new assumptions, we now value E.ON's power-generation business at an EV of Euro 28.7bn, compared with Euro 24bn previously. Our new EV for the power-generation business of RWE is Euro 28.7bn, compared with 23bn previously.

Figure 58: RWE increase in value of power plants on new assumptions (Euro m)

Fuel type	Previous valuation (Euro m)	New valuation (Euro m)	Difference (Euro m)	Difference per share
Nuclear	7,789	9,988	2,199	3.9
Lignite	11,194	14,291	3,097	5.5
Coal	2,574	2,745	171	0.3
Other	1,638	1,638	0	0.0
TOTAL	23,195	28,662	5,467	9.7

Source: Deutsche Bank

In total, then, the changes we have made to our assumptions on power prices and nuclear-life extensions adds Euro 7.2/share to our valuation of E.ON (Figure 57), and Euro 9.7/share to our valuation of RWE (Figure 58).

Conclusion and risks

In our view, Germany's energy policy must be radically overhauled in the near future.

If the Government is serious about its declared policy objectives of reducing carbon emissions significantly and ensuring security of supply, then we see no other realistic option open to the Government than to extend the lifetime of the country's nuclear-power stations while encouraging a rapid development of clean-coal power plants. As a result, we now assume that this is how policy will develop in Germany in our base-case valuations of E.ON and RWE.

The main risks to our revised valuations are that gas and carbon prices are lower in future than we are now assuming, and/or that the European carbon-trading scheme breaks down in future, thereby making conventional coal the new entrant of choice and therefore reducing our long-term power-price forecast.

To conclude this report, we now briefly review the valuations and investment cases for E.ON and RWE separately.

Model updated: 15 August 2006

Running the Numbers

Europe

Germany

Electricity

E.ON

Reuters: EONG.DE Bloomberg: EOA GY

Buy

Price as of 16 January EUR 100.28

Target price EUR 118.00

Company website

http://www.eon.com

Company description

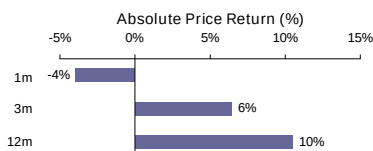
E.ON AG generates and distributes electricity and distributes gas and district heating to industrial, commercial and residential customers. The company stores and distributes gas and develops real estate. E.ON operates in Europe and North America.

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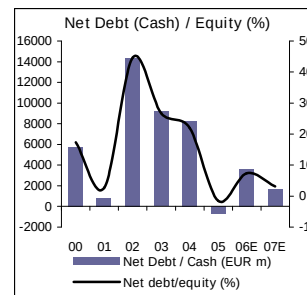
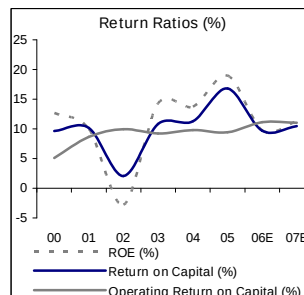
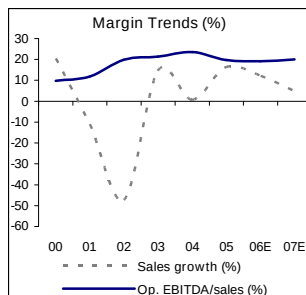
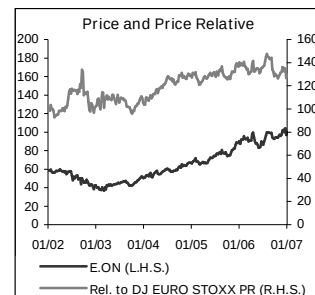
52-week Range: EUR 82.12 - 104.40

Market Cap (m) EUR 66,285 USD 85,709

Company identifiers

Cusip NA SEDOL 4942904

Year Ending 31 December	2000	2001	2002	2003	2004	2005	2006E	2007E
SUMMARY								
Headline EPS (EUR)	3.67	3.14	3.86	5.00	5.30	5.28	6.62	7.67
P/E ratio Headline (x)	15.0	18.4	13.7	8.7	10.9	13.9	15.2	13.1
Headline EPS growth (%)	5.2	-14.4	23.2	29.3	6.0	-0.4	25.4	15.9
EPS FD (EUR)	4.74	3.87	-1.07	6.04	6.61	11.24	6.51	7.67
P/E ratio FD (x)	11.6	14.9	nm	7.2	8.8	6.5	15.4	13.1
Operating CFPS (EUR)	5.36	5.80	10.84	8.47	9.08	10.02	3.88	13.71
Free CFPS (EUR)	-0.71	0.21	6.95	3.54	4.87	4.25	-2.63	6.92
P/CFPS (x)	10.3	10.0	4.9	5.1	6.4	7.3	25.9	7.3
DPS (EUR)	1.35	1.60	1.75	2.00	2.35	7.00	3.50	4.00
Dividend Yield (%)	2.5	2.8	3.3	4.6	4.1	9.6	3.5	4.0
BV/Share (EUR)	38.61	36.30	39.34	45.52	51.08	67.50	66.49	70.03
Price/BV (x)	1.68	1.60	0.98	1.14	1.31	1.29	1.51	1.43
Weighted average shares (m)	726	674	652	654	657	659	661	663
Average market cap (EUR m)	39,962	38,999	34,446	28,328	38,069	48,199	66,285	66,285
Enterprise value (EUR m)	57,199	62,140	71,080	56,788	66,694	64,373	82,994	82,538
EV/Sales	0.69	0.85	1.84	1.28	1.50	1.24	1.43	1.35
EV/EBITDA	7.1	7.2	9.3	6.0	6.3	6.3	7.4	6.7
EV/EBIT	18.2	14.6	15.0	9.1	9.1	8.8	10.2	9.1
EV/Operating Capital	1.5	1.5	1.3	1.1	1.2	1.2	1.5	1.4
INCOME STATEMENT (EUR m)								
Sales revenue	82,456	73,337	38,545	44,204	44,539	51,854	58,161	60,967
Operating EBITDA	8,041	8,626	7,680	9,458	10,515	10,272	11,144	12,243
Depreciation	4,032	3,775	2,924	3,110	2,851	2,857	3,029	3,191
Amortisation	873	588	24	120	308	82	0	0
EBIT	3,136	4,263	4,732	6,228	7,356	7,333	8,115	9,052
Net interest income(expense)	-117	-1,206	-1,493	-1,169	-1,003	-775	-819	-729
Associates/affiliates	341	1,280	1,033	0	0	0	0	0
Investment/other income(expense)	-363	-372	-381	-494	-137	-252	-173	-132
Exceptionals/extraordinaries	3,501	-67	-4,594	973	578	3,930	-500	0
Income tax expense	2,542	761	-645	1,124	1,947	2,276	1,685	2,457
Minorities/preference dividends	516	527	637	464	504	553	634	650
Net income	3,440	2,610	-696	3,950	4,343	7,407	4,305	5,084
CASH FLOW (EUR m)								
Cash flow from operations	3,889	3,907	7,066	5,538	5,967	6,601	2,564	9,088
Movement in net working capital	-2,297	-2,899	2,869	-1,191	-767	-1,027	-611	-271
Capex	-4,408	-3,768	-2,532	-3,220	-2,770	-3,800	-4,300	-4,500
Free cash flow	-519	139	4,534	2,318	3,197	2,801	-1,736	4,588
Other investing activities	-1,909	15,972	-10,698	-141	-358	6,062	2,300	0
Equity raised(bought back)	-925	-3,539	0	0	0	0	0	0
Dividends paid	-538	-628	-1,523	-1,614	-1,616	-1,794	-4,941	-2,606
Net inc(dec) in borrowings	0	0	0	0	0	0	0	0
Other financing cash flows	0	0	0	2,200	1,232	2,690	0	0
Total cash flows from financing	-1,463	-4,167	-1,523	586	-384	896	-4,941	-2,606
Net cash flow	-3,891	11,944	-7,687	2,763	2,455	9,759	-4,377	1,983
Movement in net debt(cash)	3,891	-11,944	7,687	-2,763	-2,455	-9,759	4,377	-1,983
BALANCE SHEET (EUR m)								
Cash and other liquid assets	8,501	12,144	8,385	10,795	12,016	15,119	10,742	12,724
Tangible fixed assets	28,844	34,286	41,989	42,836	43,563	41,323	40,294	41,603
Goodwill	5,647	6,242	13,108	12,331	12,469	13,466	13,466	13,466
Other intangible assets	4,067	4,216	5,932	5,738	5,773	6,022	6,022	6,022
Associates/investments	24,782	15,297	16,971	17,725	17,263	21,686	21,686	21,686
Other assets	34,374	26,861	26,680	22,425	22,978	28,946	30,149	30,682
Total assets	106,215	99,046	113,065	111,850	114,062	126,562	122,358	126,184
Interest bearing debt	14,246	12,987	22,765	19,994	20,301	14,362	14,362	14,362
Other liabilities	58,813	55,235	58,136	57,457	56,057	62,982	58,681	59,378
Total liabilities	73,059	68,222	80,901	77,451	76,358	77,344	73,043	73,740
Shareholders' equity	28,033	24,462	25,653	29,774	33,560	44,484	43,948	46,427
Minorities	5,123	6,362	6,511	4,625	4,144	4,734	5,368	6,017
Total shareholders' equity	33,156	30,824	32,164	34,399	37,704	49,218	49,316	52,444
Net working capital	18,028	10,717	9,180	4,678	13,194	15,644	16,255	16,527
Net debt(cash)	5,745	843	14,380	9,199	8,285	-757	3,620	1,638
Capital	38,901	31,667	46,544	43,598	45,989	48,461	52,936	54,081
RATIO ANALYSIS								
Sales growth (%)	20.5	-11.1	-47.4	14.7	0.8	16.4	12.2	4.8
Op. EBITDA/sales (%)	9.8	11.8	19.9	21.4	23.6	19.8	19.2	20.1
EBIT/sales (%)	3.8	5.8	12.3	14.1	16.5	14.1	14.0	14.8
Payout ratio (%)	28.5	41.3	nm	33.1	35.6	62.3	53.7	52.1
ROE (%)	12.7	9.9	-2.8	14.3	13.7	19.0	9.7	11.3
Return on Capital (%)	9.6	10.1	2.0	10.8	11.3	16.8	9.7	10.5
Operating Return on Capital (%)	5.1	8.6	9.9	9.2	9.8	9.4	11.1	11.0
Capex/sales (%)	5.3	5.1	6.6	7.3	6.2	7.3	7.4	7.4
Capex/depreciation (x)	1.1	1.0	0.9	1.0	1.0	1.3	1.4	1.4
Net debt/equity (%)	17.3	2.7	44.7	26.7	22.0	-1.5	7.3	3.1
Net interest cover (x)	26.8	3.5	3.2	5.3	7.3	9.5	9.9	12.4



Source: Company data, Deutsche Bank estimates

Europe Germany
Utilities Electricity

18 January 2007

E.ON

Reuters: EONG.DE Bloomberg: EOA GY

Undervalued growth

Insights and catalysts

- Significant increases in German forward electricity prices should boost profits at E.ON's German nuclear and coal fleet, although, owing to the lag between higher wholesale prices and higher retail prices, the full benefit of higher prices will take until 2008E to feed through into reported numbers.
- While the issue of nuclear life extensions does not currently appear to be a major policy priority for the coalition Government (the SPD and CDU/CDS are in disagreement over the issue), increasing political pressure to take action to combat climate change should lead to renewed attempts to resolve the issue. As argued in the main body of this report, we believe that sooner rather than later nuclear extensions are the only viable policy option. As a result, we now price in a 28-year extension to 60 years in our base-case valuation of E.ON.
- E.ON's decision to walk away from the potential acquisition of Scottish Power (albeit after submitting a bid for 570p), highlights increased management discipline at the company – they are unwilling to complete a strategic acquisition at any price. In our view this reduces reinvestment risk and gives reassurance that the company will be disciplined in its bid for Endesa.
- E.ON's balance sheet is materially underleveraged – we estimate the company will have net debt of only Euro 3.6bn at 2006 year end. There is therefore scope to increase leverage, either through acquisition or via share buybacks. Such a move would almost certainly prove earnings enhancing.

Valuation and risks

We derive our Euro 118/share price target from a sum-of-the-parts analysis (see next page for details). E.ON trades significantly below sector average multiples on 13x 2007E P/E versus the sector on 16.1x and a 6.8x 2007E EV/EBITDA versus the sector on 8.1x. Stripping out the value of E.ON's stake in Gazprom (which makes only minimal contribution to its P&L), the stock looks even cheaper, trading on 5.8x 2007E EV/EBITDA and 10.5x 2007E P/E. The main risks to our revised valuations are that gas and carbon prices are lower in future than we are now assuming.

Forecasts and ratios

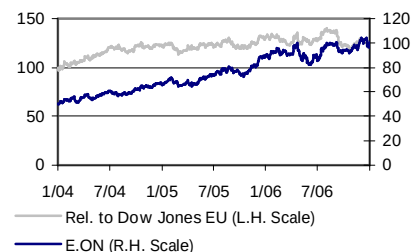
Year End Dec 31	2004A	2005A	2006E	2007E
EBITDA (EURm)	10,515	10,272	11,144	12,243
PBT DB (EURm)	5,931	6,306	6,691	8,191
DB EPS (EUR)	5.30	5.28	6.62	7.67
DB EPS growth (%)	6.0	-0.4	25.4	15.9
P/E (DB EPS) (x)	10.9	13.9	15.2	13.1
EV/EBITDA (x)	6.4	6.3	7.5	6.8
DPS (EUR)	2.35	7.00	3.50	4.00
Yield (%)	4.1	9.6	3.5	4.0

Source: Deutsche Bank estimates, company data

Buy

Price at 16 Jan 2007 (EUR)	100.28
Price Target (EUR)	118.00
52-week range (EUR)	104.40 – 100.28

Price/price relative



Performance (%)	1m	3m	12m
Absolute	-3.9	6.3	10.5
Dow Jones EURO			
STOXX Price	1.5	6.1	18.5

Stock data

Market cap (EUR)(m)	66,285.1
Shares outstanding (m)	661
Free float (%)	89
Dow Jones EURO STOXX Price	401.3

Key indicators

ROE (%)	9.7
ROA (%)	4.4
Net debt/equity (x)	7.3
Book value/share (EUR)	66.5
Price/book (x)	1.5
Net interest cover (x)	9.9
EBIT margin (x)	14.0

We value E.ON on a sum-of-the-parts basis to derive our new target price of Euro 118/share , compared with Euro 110 previously (Figure 59).

Figure 59: E.ON, Sum-of-the-Parts Valuation

	Euro m	Euro/share	Comment
Central Europe (Electricity)	45,650	69	
Generation (Germany/Europe ex Scandi)	30,226	46	Based on plant by plant SoTPs
German Transmission network	2,495	4	Based on estimated RAB
German Elec Distr. Networks	6,433	10	Based on estimated RAB
German Gas Distr. Networks	4,144	6	Based on 7x 2006E EV/EBITDA
CEE distr. Assets	2,353	4	Based on 25% premium to acquisition price
Pan-Europe Gas	18,234	28	
German Gas Upstream/Midstream	12,424	19	Based on 8x 2006E EV/EBITDA
German Gas Downstream (incl. Thuga)	5,810	9	Based on 7x 2006E EV/EBITDA
UK (Powergen)	10,764	16	
UK Generation	4,807	7	Based on plant by plant SoTPs
UK Retail Supply	2,617	4	Based on £200 per discreet customer
Midland and East Midlands Distr.	3,340	5	Based on 10% premium to RAB in March 06
Nordic	10,032	15	
Sydkraft	7,725	12	Based on put-option value of E2.2bn
Grange	1,726	3	Based on acquisition EV E1726bn
E.ON (Finland)	581	1	Based on Fortum's call option exercise price + net cash
US Mid-West (LG&E)	4,464	7	Based on comparable US companies
Connect Austria (One)	165	0	Equity value within EV of E1.6bn with E1.27bn of debt
Gazprom Stake	12,330	19	6.4% stake at current market prices with 10% disc for CGT
SPP stake + Gasum Oy stake	1,212	2	SPP based on acquisition price.
BKW Stake	746	1	Based upon current market price
Share investments, associates and affiliates	9,492	14	Book value (excluding those above and German generation)
Total Assets	113,089	172	
Net Debt (year-end 2005E)	-3,620	-5	Based on net debt but excluding securities held as fixed assets
Other financial assets	360	1	Financial Receivables from affiliates and associates
Nuclear provisions	-8,498	-13	Adjusted nuclear decommissioning provision
Other provisions	-15,294	-23	Pensions, taxes, personnel and environmental costs
Minorities	-8,242	-13	Based on 2006 P/E of 12x
Total Equity	77,795	118	

Source: Deutsche Bank

The main changes against our previous valuation are as follows:

- As explained in Section 4 above, we now value the German power-generation business at an EV of Euro 28.8bn, compared with Euro 24bn previously (Figure 57 above). This adds Euro 7.3/share to our valuation.
- We have updated our estimates for E.ON's year-end 2006 net debt, and made other minor adjustments to the value of the group's portfolio of financial assets after the group's 9m results last November. This adds Euro 1/share to our valuation.

With 18% upside to our new price target of Euro 118/share, and E.ON yielding 4% on our 2007E estimates, the stock offers total potential upside of 22% from current levels, and we re-iterate our BUY recommendation.

E.ON Valuation and risks

We value E.ON using a sum-of-the-parts methodology with the bulk of the value coming from E.ON Energie (especially the German generation assets) and the Ruhrgas business.

We have valued the German and European generation plants using a DCF methodology assuming a long-term power price of Euro 50/MWh, with gas as the new-entrant fuel of choice. This is based on a mid-cycle oil price forecast of \$44/boe, a thermal-equivalent gas price of Euro 5.35/GJ, and a long-term carbon price of Euro 25/tonne. We also assume an extension of Germany's nuclear power plants to 60 years, and a 50% tax rate on all nuclear output going forward, with the proceeds used to make CCS competitive with gas.

We also use a DCF methodology to value the UK power-generation plants, but use a higher long-term power price for the UK of £43/MWh, again reflecting the thermal equivalence with oil.

We value the German network businesses (power and gas) on the basis of the assumed RAB values using European peer companies in the UK and continental Europe as cross references.

On the basis of our new assumptions, our price target for E.ON is Euro 118/share.

The main risks to our valuation is that gas and carbon prices are lower in future than we are now assuming, and/or that the European carbon-trading scheme breaks down in future, thereby making conventional coal the new entrant of choice and therefore reducing our long-term power-price forecast. The other main downside risk to our valuation and earnings estimates is the future impact of utility regulation in Germany.

Model updated: 17 January 2007

Running the Numbers

Europe

Germany

Electricity

RWE

Reuters: RWE.GE

Bloomberg: RWE GY

Buy

Price as of 16 January EUR 81.80

Target price EUR 94.00

Company website

http://www.rwe.de

Company description

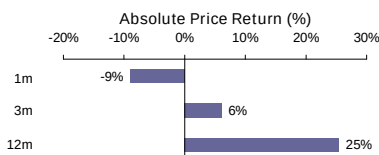
RWE AG, through subsidiaries, generates electricity, mines coal, offers waste disposal and recycling services and supplies drinking water. The company operates worldwide.

Research Team

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52-week Range: EUR 61.56 - 89.85

Market Cap (m) EUR 45,545

USD 58,891

Company identifiers

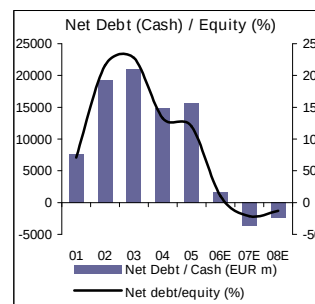
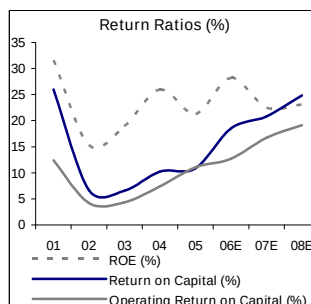
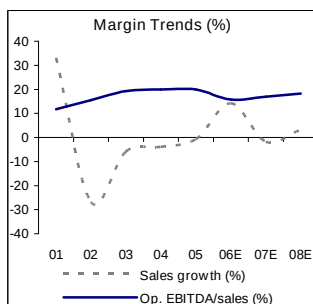
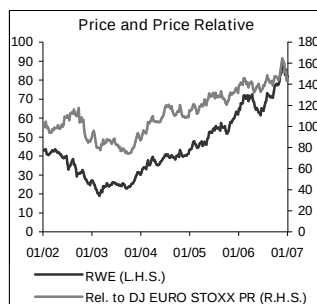
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SEDOL

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Year Ending 31 December	2001	2002	2003	2004	2005	2006E	2007E	2008E
SUMMARY								
Headline EPS (EUR)	4.31	2.06	3.97	3.19	4.05	4.48	5.94	6.73
P/E ratio Headline (x)	10.1	17.9	6.2	11.9	12.7	18.2	13.8	12.2
Headline EPS growth (%)	128.5	-52.2	92.6	-19.7	26.9	10.7	32.5	13.2
EPS FD (EUR)	3.83	1.87	2.22	3.80	4.00	6.41	5.94	6.73
P/E ratio FD (x)	11.4	19.8	11.1	10.0	12.8	12.8	13.8	12.2
Operating CFPS (EUR)	10.47	11.71	10.59	4.91	9.67	12.25	8.27	10.43
Free CFPS (EUR)	4.24	-3.55	-3.78	4.72	3.45	26.84	12.67	1.54
P/CFPS (x)	4.2	3.2	2.3	7.7	5.3	6.7	9.9	7.8
DPS (EUR)	1.00	1.10	1.25	1.50	1.75	3.30	3.82	3.23
Dividend Yield (%)	2.3	3.0	5.1	4.0	3.4	4.0	4.7	3.9
BV/Share (EUR)	14.88	11.43	12.06	17.17	20.40	25.06	27.70	30.60
Price/BV (x)	2.85	2.16	2.60	2.37	3.07	3.26	2.95	2.67
Weighted average shares (m)	565	562	562	562	562	562	562	562
Average market cap (EUR m)	24,221	20,501	13,720	21,061	28,608	45,545	45,545	45,545
Enterprise value (EUR m)	57,137	63,912	59,092	55,527	56,185	59,359	54,444	56,086
EV/Sales	0.90	1.37	1.35	1.32	1.34	1.24	1.16	1.16
EV/EBITDA	7.6	8.8	7.0	6.6	6.7	7.9	6.8	6.3
EV/EBIT	14.1	17.2	13.3	10.0	9.5	11.7	8.8	8.0
EV/Operating Capital	1.5	1.3	1.1	1.3	1.5	2.3	2.4	2.2
INCOME STATEMENT (EUR m)								
Sales revenue	63,776	46,633	43,875	42,137	41,819	47,744	46,855	48,324
Operating EBITDA	7,471	7,241	8,476	8,400	8,324	7,544	7,967	8,836
Depreciation	3,039	2,687	2,925	2,836	2,423	2,473	1,794	1,830
Amortisation	373	830	1,100	492	1,014	621	0	0
EBIT	4,059	3,724	4,451	5,564	5,901	5,071	6,172	7,006
Net interest income(expense)	-477	-1,030	-1,320	-1,130	-985	-850	200	100
Associates/affiliates	471	0	266	412	301	706	272	275
Investment/other income(expense)	-1,084	-1,602	-1,528	-1,355	-700	-1,152	-1,228	-1,254
Exceptionals/extraordinaries	167	1,630	550	936	326	1,519	0	0
Income tax expense	478	1,367	1,186	1,521	1,221	910	1,896	2,145
Minorities/preference dividends	496	305	-17	277	356	160	180	200
Net income	2,162	1,050	1,249	2,137	2,251	3,603	3,340	3,783
CASH FLOW (EUR m)								
Cash flow from operations	5,910	6,584	5,958	2,763	5,438	6,892	4,650	5,865
Movement in net working capital	-590	1,408	232	-623	1,987	324	-985	-256
Capex	-3,518	-8,581	-8,082	-3,429	-3,500	-4,500	-5,000	-5,000
Free cash flow	2,392	-1,996	-2,124	2,654	1,938	15,092	7,123	865
Other investing activities	-5,634	-5,350	1,150	3,012	0	12,700	7,473	0
Equity raised(bought back)	-2,040	0	3,000	0	0	0	0	0
Dividends paid	-523	-570	-619	-703	-844	-984	-1,858	-2,150
Net inc(dec) in borrowings	0	0	0	0	0	0	0	0
Other financing cash flows	0	-3,350	-3,200	0	0	0	0	0
Total cash flows from financing	-2,563	-3,920	-819	-703	-844	-984	-1,858	-2,150
Net cash flow	-5,805	-11,266	-1,793	1,643	1,095	14,108	5,266	-1,286
Movement in net debt(cash)	5,805	11,266	1,793	-1,643	-1,095	-14,108	-5,266	1,286
BALANCE SHEET (EUR m)								
Cash and other liquid assets	6,289	10,602	12,009	12,539	11,775	11,775	27,775	27,775
Tangible fixed assets	31,720	33,779	40,905	35,025	36,565	25,892	21,625	24,794
Goodwill	7,802	16,972	19,072	17,718	17,215	17,215	17,215	17,215
Other intangible assets	549	1,546	1,546	0	0	0	0	0
Associates/investments	5,934	5,927	5,919	5,887	12,774	12,774	12,774	12,774
Other assets	35,132	31,447	24,594	22,201	29,793	28,538	30,063	31,390
Total assets	87,426	100,273	104,045	93,370	108,122	96,194	109,451	113,948
Interest bearing debt	13,992	29,881	33,081	27,383	27,452	13,344	24,078	25,364
Other liabilities	62,591	61,468	61,706	54,794	67,553	67,115	68,154	69,733
Total liabilities	76,583	91,349	94,787	82,177	95,005	80,459	92,232	95,097
Shareholders' equity	7,321	6,429	6,780	9,656	11,474	14,093	15,576	17,208
Minorities	3,522	2,495	2,478	1,537	1,643	1,643	1,643	1,643
Total shareholders' equity	10,843	8,924	9,258	11,193	13,117	15,736	17,219	18,851
Net working capital	14,546	16,853	12,519	4,976	1,205	883	1,062	1,425
Net debt(cash)	7,703	19,279	21,072	14,844	15,677	1,569	-3,697	-2,411
Capital	18,546	28,203	30,330	26,037	28,794	17,305	13,522	16,440
RATIO ANALYSIS								
Sales growth (%)	33.1	-26.9	-5.9	-4.0	-0.8	14.2	-1.9	3.1
Op. EBITDA/sales (%)	11.7	15.5	19.3	19.9	19.9	15.8	17.0	18.3
EBIT/sales (%)	6.4	8.0	10.1	13.2	14.1	10.6	13.2	14.5
Payout ratio (%)	26.1	58.9	56.3	39.5	43.7	51.6	64.4	48.0
ROE (%)	31.6	15.3	18.9	26.0	21.3	28.2	22.5	23.1
Return on Capital (%)	26.0	6.7	6.6	10.2	10.9	18.5	20.8	24.8
Operating Return on Capital (%)	12.4	4.2	4.3	7.4	11.0	12.7	16.7	19.1
Capex/sales (%)	5.5	18.4	18.4	8.1	8.4	9.4	10.7	10.3
Capex/depreciation (x)	1.2	3.2	2.8	1.2	1.4	1.8	2.8	2.7
Net debt/equity (%)	71.0	216.0	227.6	132.6	119.5	10.0	-21.5	-12.8
Net interest cover (x)	8.5	3.6	3.4	4.9	6.0	6.0	nm	nm



Source: Company data, Deutsche Bank estimates

Europe Germany
Utilities Electricity

18 January 2007

RWE

Reuters: RWE.G.DE Bloomberg: RWE GY

Power gearing

Insights and catalysts

- Significant increases in German forward electricity prices should boost profits at RWE's German nuclear and lignite fleet, although, owing to the lag between higher wholesale prices and higher retail prices, the full benefit of higher prices will take until 2008 to feed through into reported numbers.
- While the issue of nuclear life extensions does not currently appear to be a major policy priority for the coalition Government (the SDP and CDU/CDS are in disagreement over the issue), increasing political pressure to take action to combat climate change should lead to renewed attempts to resolve the issue. As argued in the main body of this report, we believe that sooner rather than later nuclear extensions are the only viable policy option. As a result, we now price in a 28-year extension to 60 years in our base-case valuation of RWE.
- RWE's balance sheet is materially underleveraged. Following its disposal of Thames Water, the company will, on our estimates, have net cash of Euro 3bn at 2006E year end. Even allowing for the planned off-balance-sheet financing of approximately Euro 8bn in 2007, this will leave scope to increase leverage, either through small-to-mid sized acquisitions or share buybacks. Such a move would almost certainly prove earnings enhancing.
- Management remains extremely focused and disciplined, and, as a result, we are not concerned about the prospect of re-investment risk.

Valuation

We derive our Euro 94 price target from a sum-of-the-parts analysis (see next page for details). RWE trades below sector-average multiples on 13.7x 2007E P/E versus the sector on 16.1x and a 6.8x 2007E EV/EBITDA versus the sector on 8.1x. The main risks to our revised valuations are that gas and carbon prices are lower in future than we are now assuming.

Forecasts and ratios

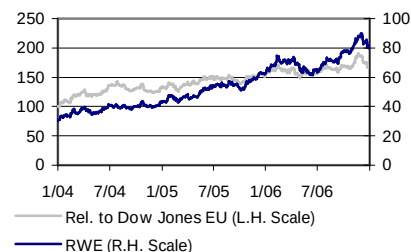
Year End Dec 31	2004A	2005A	2006E	2007E	2008E
EBITDA (EURm)	8,400	8,324	7,544	7,967	8,837
EBBT DB (EURm)	5,564	5,901	5,071	6,172	7,006
DB EPS (EUR)	3.19	4.05	4.48	5.94	6.73
DB EPS growth (%)	-19.7	26.9	11.7	32.5	13.2
P/E (DB EPS) (x)	25.5	20.4	18.2	13.7	12.1
EV/EBITDA (x)	6.6	6.7	7.9	6.8	6.3
DPS (EUR)	1.50	1.75	3.30	3.82	3.23
Yield (%)	1.8	2.1	4.0	4.7	4.0

Source: Deutsche Bank estimates, company data

Buy

Price at 16 Jan 2007 (EUR)	81.80
Price Target (EUR)	94.00
52-week range (EUR)	89.85 - 61.56

Price/price relative



Performance (%)	1m	3m	12m
Absolute	-9.0	4.8	25.5
Dow Jones EURO			
STOXX Price	1.5	6.1	18.5

Stock data

Market cap (EUR)(m)	46,004.7
Shares outstanding (m)	562
Free float (%)	67
Dow Jones EURO STOXX Price	401.3

Key indicators

ROE (%)	22.3
ROA (%)	3.4
Net debt/equity (x)	102.5
Book value/share (EUR)	23.6
Price/book (x)	3.5
Net interest cover (x)	8.1
EBIT margin (x)	14.1

We value RWE on a sum-of-the-parts basis to derive our new target price of Euro 94/share, compared with Euro 77.5 previously (Figure 60).

Figure 60: RWE, Sum-of-the-Parts Valuation

	Euro m	Euro/share	Comment
RWE Power	36,103	57	
Generation (Germany/Europe)	31,788	46	Based on plant by plant SoTPs
RWE-DEA	4,315	8	Based on Woodmac valuation
RWE nPower	6,082	37	
UK Generation	4,226	8	Based on plant by plant SoTPs
UK Retail Supply	1,856	3	Based on £200 per discrete customer
RWE Energy	20,763	37	
German Transmission network	2,924	5	Based on estimated RAB
Czech Gas Transmission Networks	4,320	8	Based on 20% premium to acquisition price
German Elec Distr. Networks	6,993	12	Based on estimated RAB
German Gas Downstream	3,416	6	Based on implied buy-out price
CEE excl. Czech gas	1,737	3	Estimated acquisition price
Dutch gas distribution	450	19	Based on acquisition price
Kalag Austria	330	1	Acquisition price
RWE Water	8,050	14	
AWW	7,300	13	Based on US water-market comps
Berlin Water	750	1	Estimated value at 10x EV/EBIT
Total Assets	70,998	126	
(Net Debt)/Cash (year-end 2006E)	4,146	7	Based on net debt but excluding securities held as fixed assets
Financial assets	1,880	3	Financial Receivables from affiliates and associates
Nuclear provisions	-6,597	-12	Adjusted nuclear decommissioning provision
Other provisions	-17,021	-30	Pensions, taxes, personnel and environmental costs
Deferred tax asset	2,042	4	Deferred tax asset on pension and nuclear provisions
Minorities	-2,625	-5	Based on 200E P/E of 15x
Total Equity	52,823	94	

Source: Deutsche Bank

The main changes against our previous valuation are as follows:

- As explained in Section 4 above, we now value the German power-generation business at an EV of Euro 28.7bn, compared with Euro 23bn previously (Figure 58 above). This adds Euro 9.7/share to our valuation.
- We have updated our estimates for RWE's year-end 2006 net debt to take account of the sale of Thames Water (completed in December 2006), and made other adjustments to the value of the group's portfolio of financial assets after the group's 9m results last November. The disposal of Thames was achieved at a price some Euro 2bn above our previous valuation, and this adds Euro 3.6/share to our revised SotP, while taking into account favourable exchange-rate movements and marking to market the value of other assets adds a further Euro 3/share to our valuation.
- Following the group's 9m numbers we have also revised our financial forecasts for FY2006 and 2007-08, although the changes are not material. Our FY 2006E numbers for the main indicators (EBIT, net income, and recurring net income) are in line with the company's last public guidance, and our recurring EPS forecasts over 2007-08 are on average 1% higher than our previous forecasts.

With 15% upside to our new price target of Euro 94/share, and RWE yielding 4.5% on our 2007E estimates, the stock offers total potential upside of 20% from current levels, and we re-iterate our BUY recommendation.

RWE Valuation and risks

We value RWE using a sum-of-the-parts methodology with the largest value component coming from RWE Power's German generation assets (40% of group EV).

We have valued the German and European generation plants using a DCF methodology assuming a long-term power price of Euro 50/MWh, with gas as the new-entrant fuel of choice. This is based on a mid-cycle oil price forecast of \$44/boe, a thermal-equivalent gas price of Euro 5.35/GJ, and a long-term carbon price of Euro 25/tonne. We also assume an extension of Germany's nuclear power plants to 60 years, and a 50% tax rate on all nuclear output going forward, with the proceeds used to make CCS competitive with gas.

We also use a DCF methodology to value the UK power-generation plants, but use a higher long-term power price for the UK of £43/MWh, again reflecting the thermal equivalence with oil.

We value the German network businesses (power and gas) on the basis of the assumed RAB values using European peer companies in the UK and continental Europe as cross references.

On the basis of our new assumptions, our price target for RWE is Euro 94/share.

The main risks to our valuation is that gas and carbon prices are lower in future than we are now assuming, and/or that the European carbon-trading scheme breaks down in future, thereby making conventional coal the new entrant of choice and therefore reducing our long-term power-price forecast. The other main downside risk to our valuation and earnings estimates is the future impact of utility regulation in Germany.

Appendix 1

Important Disclosures

Additional information available upon request

Disclosure checklist			
Company	Ticker	Recent price*	Disclosure
E.ON	EONG.DE	98.64 (EUR) 18 Jan 07	1,2,6,7,8,14,15
RWE	RWEG.DE	80.00 (EUR) 18 Jan 07	2,6,8,14

*Prices are sourced from local exchanges via Reuters, Bloomberg and other vendors. Data is sourced from Deutsche Bank and subject companies.

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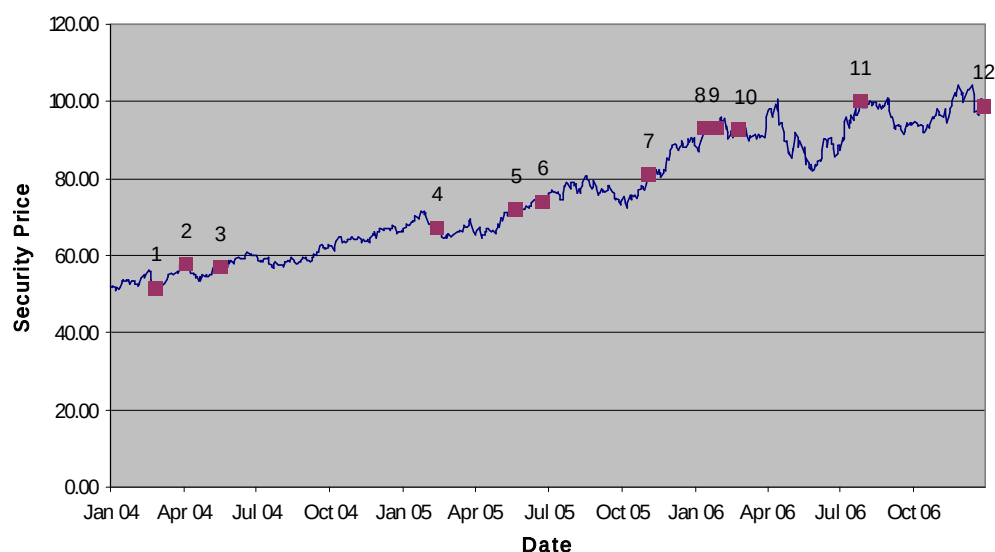
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Historical recommendations and target price: E.ON (EONG.DE)

(as of 18/01/2007)



Previous Recommendations

Strong Buy
Buy
Market Perform
Underperform
Not Rated
Suspended Rating

Current Recommendations

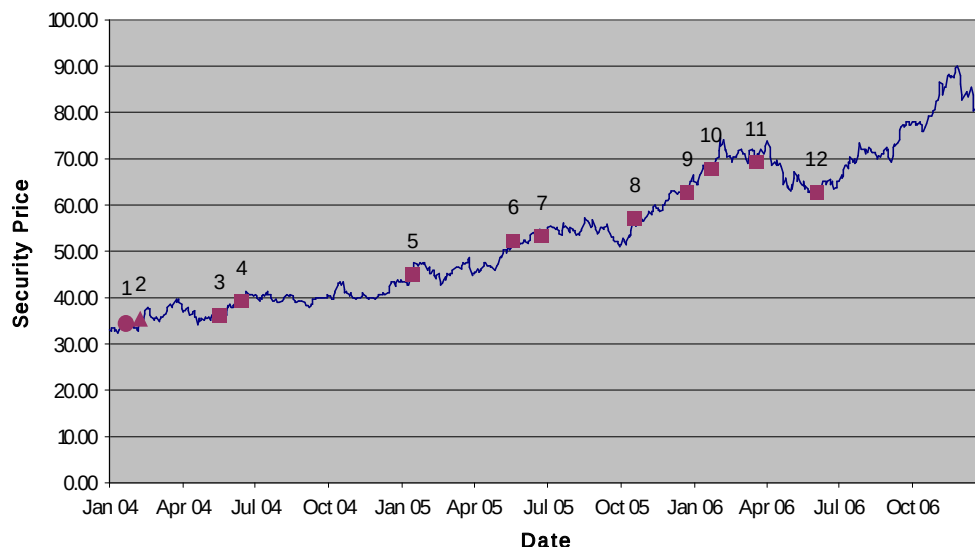
Buy
Hold
Sell
Not Rated
Suspended Rating

*New Recommendation Structure
as of September 9, 2002

1. 16/3/2004: Buy, Target Price Change EUR61.00	7. 23/11/2005: Buy, Target Price Change EUR87.00
2. 23/4/2004: Buy, Target Price Change EUR65.00	8. 1/2/2006: Buy, Target Price Change EUR99.00
3. 4/6/2004: Buy, Target Price Change EUR68.50	9. 17/2/2006: Buy, Target Price Change EUR102.00
4. 3/3/2005: Buy, Target Price Change EUR75.50	10. 14/3/2006: Buy, Target Price Change EUR105.00
5. 9/6/2005: Buy, Target Price Change EUR80.00	11. 15/8/2006: Buy, Target Price Change EUR110.00
6. 13/7/2005: Buy, Target Price Change EUR83.50	12. 17/1/2007: Buy, Target Price Change EUR118.00

Historical recommendations and target price: RWE (RWE.G.DE)

(as of 18/01/2007)



Previous Recommendations

Strong Buy
Buy
Market Perform
Underperform
Not Rated
Suspended Rating

Current Recommendations

Buy
Hold
Sell
Not Rated
Suspended Rating

*New Recommendation Structure
as of September 9, 2002

- | | |
|--|--|
| 1. 9/2/2004: Downgrade to Hold, Target Price Change EUR36.00 | 7. 14/7/2005: Buy, Target Price Change EUR59.00 |
| 2. 27/2/2004: Upgrade to Buy, Target Price Change EUR40.00 | 8. 7/11/2005: Buy, Target Price Change EUR61.50 |
| 3. 4/6/2004: Buy, Target Price Change EUR41.50 | 9. 11/1/2006: Buy, Target Price Change EUR66.00 |
| 4. 2/7/2004: Buy, Target Price Change EUR46.00 | 10. 10/2/2006: Buy, Target Price Change EUR72.00 |
| 5. 1/2/2005: Buy, Target Price Change EUR52.00 | 11. 7/4/2006: Buy, Target Price Change EUR75.00 |
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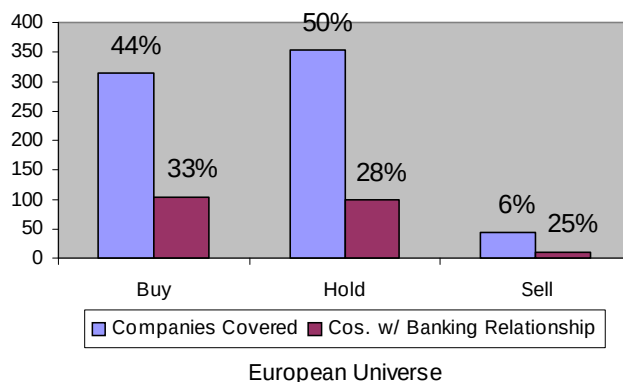
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