

Liz Bossley Consilience Energy Advisory Group, CEAG



## Power and emissions

The US department of energy (US DOE) forecasts that world electricity consumption will double between 2003 and 2030. Currently, coal and natural gas are the primary fuels used to produce electricity. In this paper, Liz Bossley compares the cost of generating electricity from coal and natural gas. As the calculations show, and based purely on carbon cost, it is more profitable to produce electricity using natural gas. However, the lower relative cost of coal *vis a vis* natural gas negates this advantage. Nevertheless, improvements in natural gas running costs and production efficiencies should, in time, reduce the industry's dependence on coal.

Today coal remains the dominant fuel for power generation. Electricity generation from nuclear power increased rapidly from the 1970s through the mid-1980s. Similarly, natural gas-fired generation grew rapidly in the 1980s and 1990s. High world oil prices have reduced the use of oil for electricity generation since the mid-1970s, with a concomitant switch from oil-fired generation to natural gas and nuclear power. Natural gas is expected to increase its share of generating capacity worldwide at the expense of oil, renewables and nuclear. Coal is expected to maintain a steady share.

From an environmental standpoint, electricity generated from peat remains the largest source of CO<sub>2</sub> emissions but the amount of peat-fired generation is minimal and declining (see Chart 1). Coal is the next dirtiest fuel and despite its constant projected share of generating capacity to 2030 this represents an increase of around 690GW.

63% of the EU allowances (EUAs) allocated in Phase 1 of the EU Emission Trading Scheme (ETS) have gone to the power generating sector. Consequently the activities of the power generation sector are directly linked to the emissions market. Early experience from the EU ETS suggests that power demand for emissions allowances is one of the main driving forces in the price of these allowances, particularly short-term fluctuations. This is a direct consequence of how the power generators choose to trade.

Installations that have been allocated 95% of the allowances they expect to need in Phase 1 could choose to generate until they have used up their free allocation, then close down. If they did so we might expect to see the lights go out across Europe on the 12 December each year. Happily, the power generators do not approach the issue in this simplistic manner. Instead, the generators, within technical limits, consider the profits they expect to make from generation each day and compare this profit against the revenue they would earn from ramping down their plant and selling the allowances instead.

When a station is deciding whether or not to generate, there are two scenarios to consider:

1) If the installation has an allocation of free allowances, the station need not buy more allowances in order to generate. However, if it does generate then it forgoes the revenue that could be earned from simply selling the allowances. Therefore, the market price of the allowances

must be added to other marginal costs as an opportunity cost in making the decision to generate;

2) If the installation has no free allowances or insufficient allowances, the station must acquire allowances in order to generate. Therefore the market price of these must be added to its other marginal operating costs when making the decision of whether or not to generate.

The objectives of the EU ETS and the Kyoto Protocol are twofold: to reduce energy demand; and, to switch from carbon intensive fuel to cleaner fuel sources. These objectives demand a realistic carbon price to provide the necessary financial incentive to cut consumption and to switch to clean power generation.

For a rough guide to the economics of this decision-making process for individual installations, based on some simplifying assumptions for illustrative purposes, consider the following two power stations:

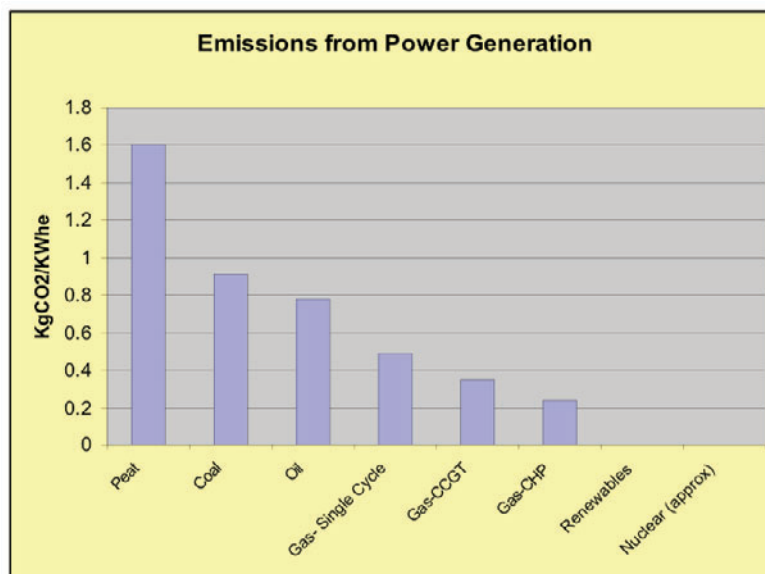
### Plant A

- Coal-fired
- 2000MW capacity
- Thermal efficiency: 36%

### Plant B

- Combined cycle gas turbine (CCGT)
- 1500MW capacity
- Thermal efficiency: 49.13%

Chart 1: Emissions from power generation



Each power station has been granted an emissions allowance under an EU ETS National Allocation Plan based upon their historical output. The number of allowances can be multiplied by the current market value of the allowances to give the cash value of the allowance allocation. This can be treated as a reduction to fixed costs.

Assume that the market price of allowances is Euro 4/t of CO<sub>2</sub> emitted and that Plant A has an annual allowance of 4,164,052t of CO<sub>2</sub> emitted. This would be worth Euro16,656,208 at that allowance market price. Plant B has an annual allowance of 2,437,016t of CO<sub>2</sub> emitted, which is worth Euro9,748,064 at that allowance price.

For simplicity's sake we will assume that fuels used in Plants A and B release the following amounts of CO<sub>2</sub> when burned, although there are variations depending on the precise type of fuel used:

Coal: 90.5kg/GJ = 0.341t/MWh

Gas: 56.1kg/GJ = 0.202t/MWh

The load factor is the running regime of the plant. A load factor of 100% implies that the plant has generated at full capacity for every half hour of the year. Load factor is principally influenced by engineers and operations and also fuel economics. A portfolio player who owns a number of power stations will clearly run their most profitable plant for longest.

Some plants can be rewarded for being flexible (this is often in the form of separate agreements negotiated between NGC and the generator). Oil tends to be the most flexible and will only generate at extremely high prices, it therefore has a low load factor and a high flexibility. Nuclear plants on the other hand cannot flex and so have a high load factor but cannot negotiate flexibility contracts with NGC.

We have assumed a 65% load factor for coal and 55% for gas. An equivalent load factor for oil would be of the order of 10–30% but the numbers are in reality very plant specific.

These figures, combined with the thermal efficiency of the station, will determine how much CO<sub>2</sub> is released per MWh of output, ignoring fixed costs. These operating parameters are outlined in Table 1

If the price, or marginal cost, of CO<sub>2</sub> is Euro4/tCO<sub>2</sub> it can be seen that an efficient gas plant has a considerable carbon marginal cost advantage over older coal stations as illustrated in Table 2.

**Carbon Cost Calculation**

Plant A

0.341t with 36% efficiency = 0.947t of CO<sub>2</sub>/MWh.  
Euro4/t of CO<sub>2</sub> allowance price = Euro2.49/MWh

Plant B

0.202t with 49.13% efficiency = 0.411t of CO<sub>2</sub>/MWh  
Euro4/t of CO<sub>2</sub> allowance price = Euro1.08/MWh

Operating Parameters	Unit	Plant A	Plant B
Fuel		Coal	Gas
Capacity	MW	2000	1500
Fuel efficiency	%	36	49.13
Load factor	%	65	55
CO <sub>2</sub> released	t CO <sub>2</sub> /MWh	0.341	0.202
CO <sub>2</sub> released/fuel efficiency	t CO <sub>2</sub> /MWh	0.947	0.411
Hours per year	hrs	8760	8760
MWh (hrs x capacity x load factor)	MWh	11,388,000	7,227,000
CO <sub>2</sub> produced	t CO <sub>2</sub>	10,784,436	2,970,297

**Table 1:** Operating parameters of Plants A and B

It may be argued that it is the net cost of emissions which should be used in the carbon calculation. For example, Plant A produces 10.6Mt of CO<sub>2</sub> and is given 4.2m EUAs. Therefore its net carbon exposure is 6.4Mt. However, by using the net carbon figure the generator is valuing the received carbon allowances at zero, when clearly they have a market value of Euro4/t. Therefore, the cost of allowances received must be valued at the market price and treated as an opportunity cost. This is why generators treat emissions as part of their marginal cost calculations along with fuel.

Based purely on carbon cost, it might therefore be expected that gas plants will generate before coal plants and that the coal plant will be squeezed out of business. However when the current comparative marginal cost of fuel is taken into account the reverse is true, as illustrated in Table 3.

The price differential between gas and electricity, i.e. the profit from buying gas and turning it into power, is known as the 'spark spread'. The price differential between coal and electricity is known as the 'dark spread'. The price differential between gas and electricity,

Carbon (opportunity) cost	Unit	Plant A	Plant B
Fuel		Coal	Gas
CO <sub>2</sub> produced	t CO <sub>2</sub>	5,974,320	2,654,280
Emissions price	Euro/ t CO <sub>2</sub>	4	4
Cost of emissions	Euro	23,897,280	10,617,120
Carbon cost	Euro/MWh	3.79	1.64
Exchange rate	Euro/£	1.52	1.52
Carbon cost	£/MWh	2.49	1.08

**Table 2:** Marginal carbon costs for Plants A and B

**Table 3:** Comparative marginal cost of fuel for Plants A and B

	Unit	Plant A	Plant B
		Coal	Gas
Coal price	US\$/t	40	
Gas price	p/Therm		30
Exchange rate	US\$/£	1.96	
Coal price	£/t	20.41	
Gas price	£/Therm		0.30
Conversion factor	t/MWh	8.14	
Conversion factor	Therm/MWh		0.0293071
Coal price	£/MWh	2.51	
Gas price	£/MWh		10.24
Coal price x fuel efficiency	£/MWh	6.96	
Gas price x fuel efficiency	£/MWh		20.84
Baseload power price	£/MWh	30	30
Dark/spark spread	£/MWh	23.04	9.16
Carbon cost	£/MWh	2.49	1.08
Clean dark/spark spread	£/MWh	20.54	8.08

taking the cost of emissions into account, is known as the 'clean spark spread'. The price differential between coal and electricity, taking the cost of emissions into account, is known as the 'clean dark spread'.

When the coal price is low relative to that of gas, the clean dark spread is greater than the clean spark spread. In other words when coal prices are low relative to gas prices there is more money to be made from coal-fired generation, even taking the cost of carbon into account. When gas prices rise so does the price of EU allowances because more coal generation is run, forcing up the price of emissions allowances. A gas plant will still generate if the clean spark spread is greater than the revenue that could be achieved by not generating and selling surplus allowances. But the coal plant will run first. Importantly, in the early stages of the EU ETS the price of carbon has not been high enough to compensate for the higher cost of gas relative to that of coal.

A similar calculation can be performed for oil-fired generation where the carbon produced is of the order of

0.28t/MWh, with a thermal efficiency of 35–40%. The price differential between oil and electricity, i.e. the profit from buying oil and turning it into power, is known as the 'slick spread'. The price differential between oil and electricity, taking the cost of emissions into account, is known as the 'clean slick spread'.

**Summary**

The overall microeconomic effect of the EU ETS is that power stations with no or low CO<sub>2</sub> output (e.g. renewables and nuclear plant) benefit from the rise in wholesale prices, with no change to marginal or fixed costs. However, because of the lack of external competition in power generation, even 'dirty' generators have received a financial benefit from the introduction of the ETS: 95% of the allowances they need have been received for free but they can pass on the marginal opportunity cost of selling these allowances in the market. Consumers lose out by covering higher marginal costs.

The significant emissions marginal cost advantage of CCGTs over coal stations should see the latter pushed towards the margins of generation. In time, assuming that the New Entrants Reserve (NER) is high enough, the cost advantage for modern, highly efficient CCGTs should see them being built more quickly than would otherwise have been the case. This will in theory decrease the power sector's CO<sub>2</sub> emissions, meeting the objectives of the EU ETS.

This article is an extract from 'Climate Change and Emissions Trading: What Every Business Needs to Know' Second Edition. Published by CEAG Ltd, January 2007.



**Power generation definitions**

Natural Gas  
*Spark spread* profit from turning gas into electricity  
*Clean spark spread* profit from turning gas into electricity taking into account the cost of CO<sub>2</sub> emissions

Coal  
*Dark spread* profit from turning coal into electricity  
*Clean dark spread* profit from turning coal into electricity taking into account the cost of CO<sub>2</sub> emissions